APPENDIX I

AIR QUALITY

APPENDIX I

AIR QUALITY

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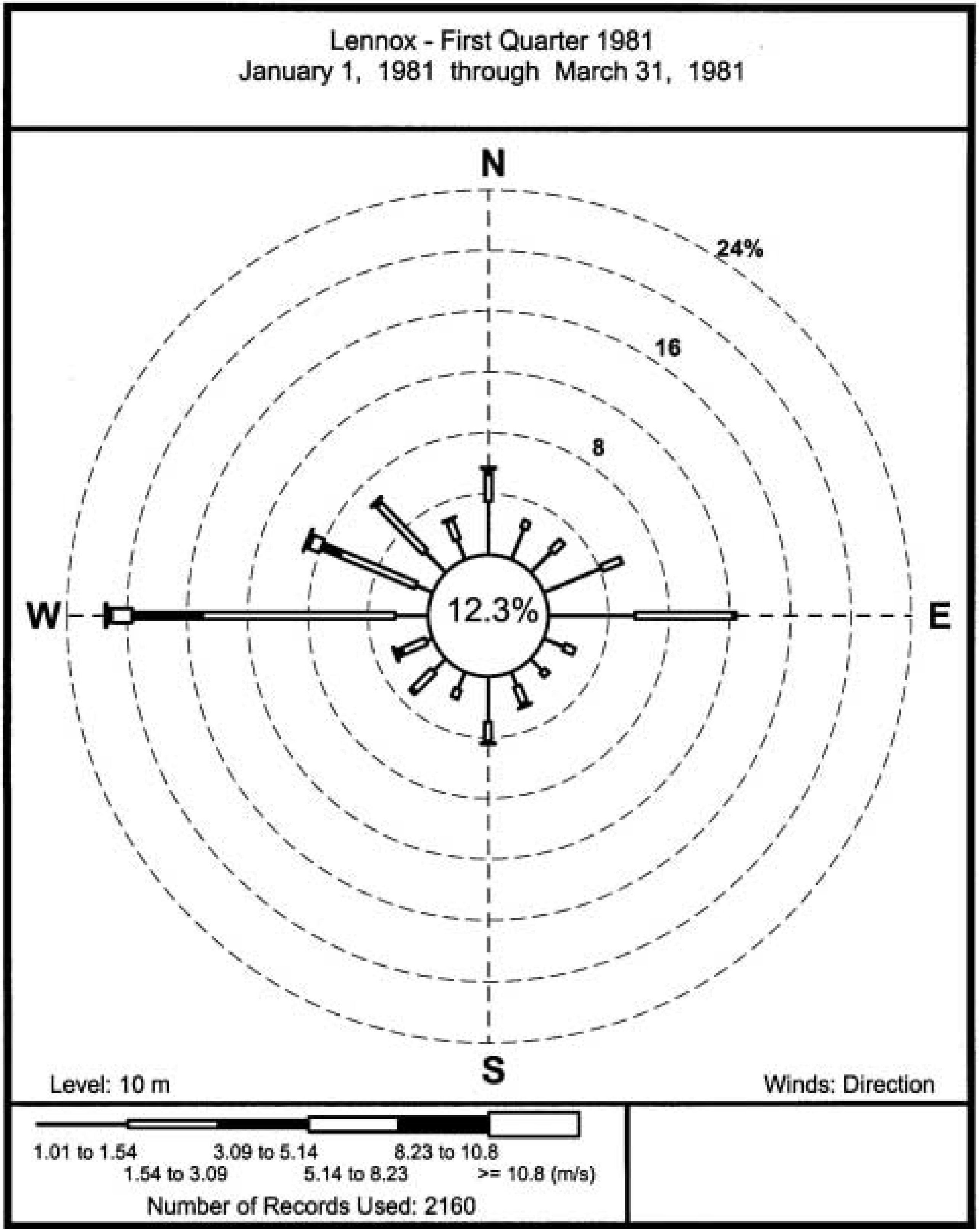
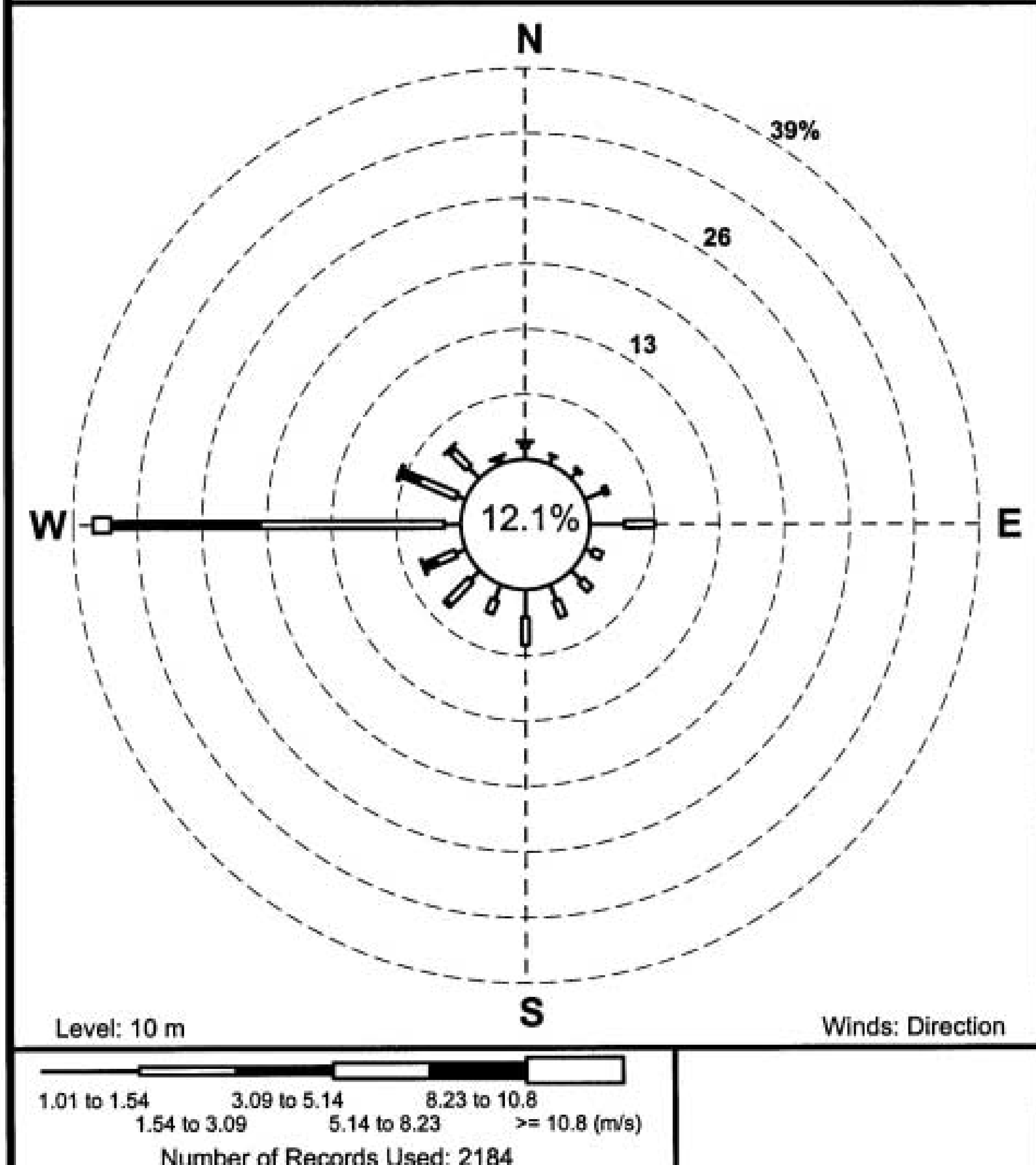
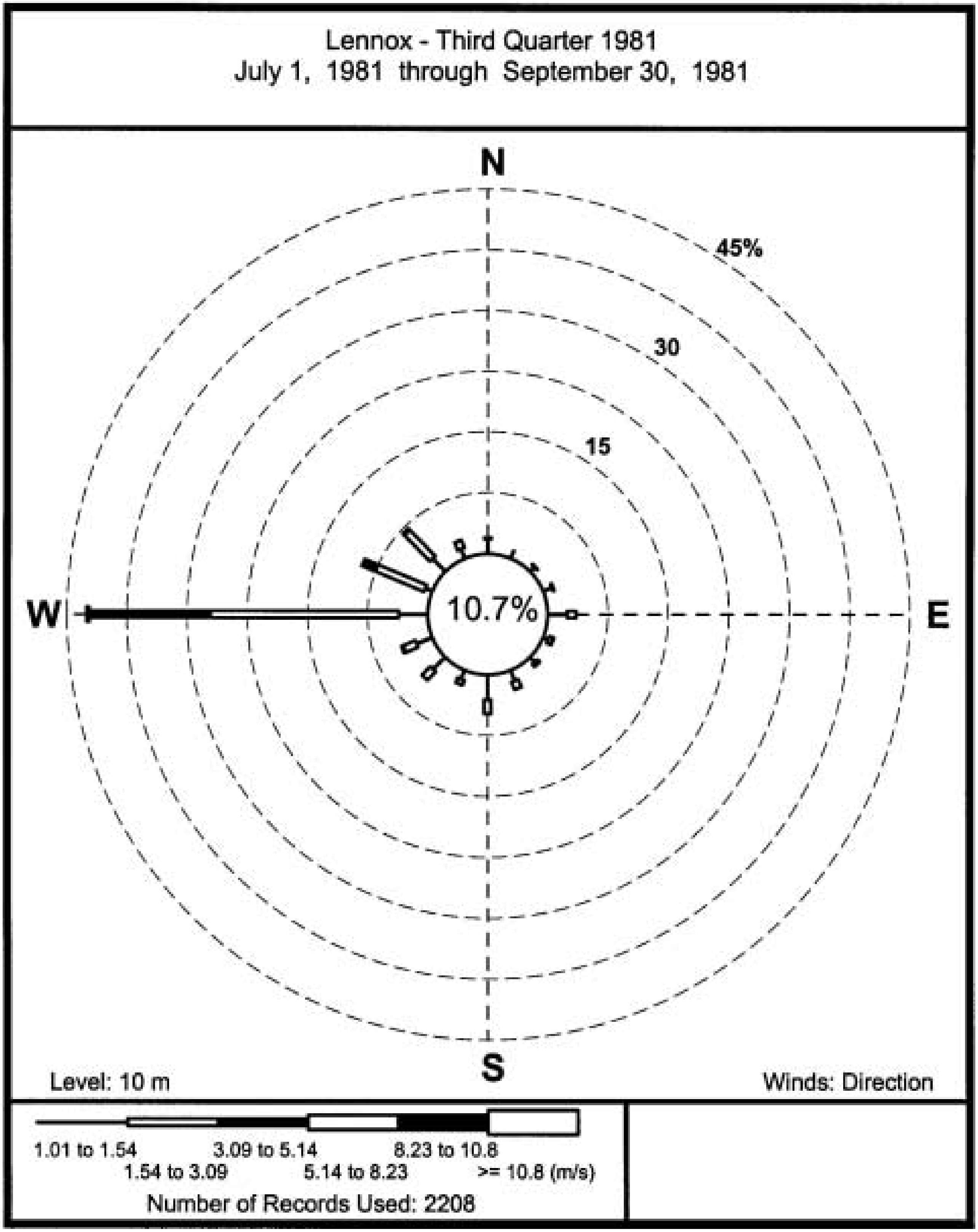
APPENDIX I.1
QUARTERLY WIND ROSES

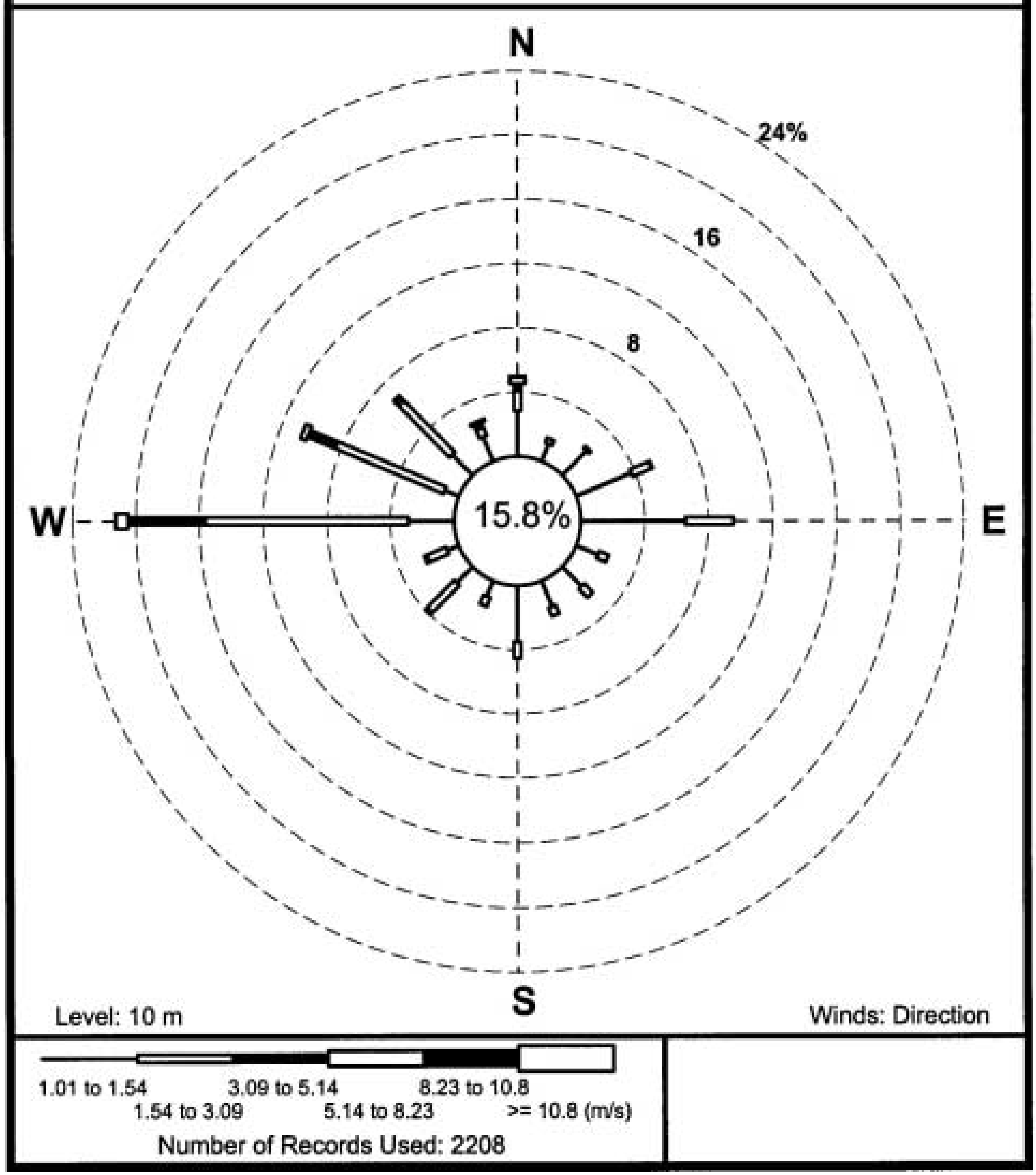

Lennox - First Quarter 1981
January 1, 1981 through March 31, 1981
N
24%
16
8
W
12.3%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2160

Lennox - Second Quarter 1981
April 1, 1981 through June 30, 1981




Lennox - Third Quarter 1981
July 1, 1981 through September 30, 1981
N
45%
30
15
W
10.7%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
1.54 to 3.09
3.09 to 5.14
5.14 to 8.23
8.23 to 10.8
>= 10.8 (m/s)
Number of Records Used: 2208

Lennox - Fourth Quarter 1981
October 1, 1981 through December 31, 1981



APPENDIX I.2
CONSTRUCTION IMPACT ANALYSIS

Appendix I.2
Construction/Demolition Phase Impacts

I.2.1 Onsite Construction

Construction of the ESPR project is expected to last 20 months, with the construction occurring in the following five main phases:

- Site preparation;
- Foundation work;
- Installation of major equipment;
- Construction/installation of major structures; and
- Start up and commissioning.

A detailed construction schedule is shown on in Section 3.8.

Site preparation includes clearing, grading, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence.

Fugitive dust emissions from the construction of the ESPR project will result from:

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.

Combustion emissions during construction will result from:

- Exhaust from the diesel construction equipment used for site preparation, grading, excavation, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from diesel-powered welding machines, electric generators, air compressors, water pumps, etc.;
- Exhaust from diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site;
- Exhaust from locomotives used to deliver mechanical equipment to the project area; and
- Exhaust from automobiles and trucks used by workers to commute to the construction site.

To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Worst-case daily dust emissions are expected to occur during the first few months of construction when site preparation occurs (i.e., month four of the construction schedule). The worst-case daily exhaust emissions are expected to occur during month six of the construction schedule. Annual emissions are based on the average equipment mix during the 20-month construction period.

I.2.2 Water Pipelines

The installation of reclaim water and firewater supply pipelines will generate short-term construction impacts including fugitive dust and construction equipment combustion emissions. The proposed pipeline route requires a total of approximately 1.9 miles of trenching. The excavation, installation of pipe, backfilling, and site cleanup will be performed in approximately 500-foot-long sections over a short duration to minimize fugitive dust and construction equipment combustion emissions.

I.2.3 Demolition Activities

The demolition activities are scheduled to occur over approximately a 6 month period during which the Units 1 and 2 will be removed. The demolition phase will not reach the workforce and equipment levels expected during the construction phase of the project. Therefore, emissions from demolition activities will be lower than emissions from construction activities and they are not assessed further.

During the demolition phase of the project, it will be necessary to remove the existing emergency firepump engine at the plant. To provide fire protection during the demolition phase, the plant will install a temporary firepump engine at the site. Since the size of the temporary firepump engine will be very similar to the existing firepump engine (i.e., less than 500 hp), the emission levels are also expected to be similar and are not assessed further.

I.2.4 Available Mitigation Measures

The following mitigation measures are proposed to control exhaust emissions from the diesel heavy equipment used during construction of the ESPR project:

- Operational measures, such as limiting engine idling time and shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and

- Use of low-emitting diesel engines meeting federal emissions standards for construction equipment if available.

The following mitigation measures are proposed to control fugitive dust emissions during construction of the project:

- Use either water application or chemical dust suppressant application to control dust emissions from unpaved surface travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surface to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials, or require all trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on unpaved surfaces to 25 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Re-plant vegetation in disturbed areas as quickly as possible;
- As needed, use gravel pads along with wheel washers or wash tires of all trucks exiting construction site that carry track-out dirt from unpaved surfaces; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant and/or use of wind breaks.

I.2.5 Estimation of Emissions with Mitigation Measures

I.2.5.1 Onsite Construction

Tables I.2-1 through I.2-3 show the estimated maximum daily and annual heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures for onsite construction activities. Detailed emission calculations are included as Attachment I.2-1.

I.2.5.2 Pipeline Construction

Table I.2-4 shows the estimated maximum daily heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures for the reclaim water and firewater supply pipeline construction activities. Because it is expected that the pipeline construction projects will take four months or less to complete, annual emissions are not shown in the following emission summary tables for these construction activities. Detailed emission calculations are included as Attachment I.2-1.

Table I.2-1
Maximum Daily Emissions During Onsite Construction
(Month 4; Maximum Dust Emissions), Pounds Per Day

	NO_x	CO	VOC	SO_x	PM_{10}
Onsite					
Construction Equipment	157.8	126.9	16.0	4.8	10.2
Fugitive Dust					27.6
Offsite					
Worker Travel, Truck/Rail Deliveries	106.4	545.7	60.8	3.1	5.0
Total Emissions					
Total	264.2	672.6	76.8	7.9	42.8

Table I.2-2
Maximum Daily Emissions During Onsite Construction
(Month 6; Maximum Exhaust Emissions), Pounds Per Day

	NO_x	CO	VOC	SO_x	PM_{10}
Onsite					
Construction Equipment	182.5	192.8	21.3	5.4	12.2
Fugitive Dust					26.5
Offsite					
Worker Travel, Truck/Rail Deliveries	261.1	836.2	95.8	10.9	10.6
Total Emissions					
Total	443.6	1,029.0	117.1	16.3	49.3

Table I.2-3
Annual Emissions During Onsite Construction, Tons Per Year

	NO_x	CO	VOC	SO_x	PM_{10}
Onsite					
Construction Equipment	14.6	25.5	2.3	0.4	1.1
Fugitive Dust					4.0
Offsite					
Worker Travel, Truck/Rail Deliveries	13.9	81.8	9.1	0.4	0.6
Total Emissions					
Total	28.5	107.3	11.4	0.8	5.7

Table I.2-4
Maximum Daily Emissions During Pipeline Construction
Pounds Per Day

	NO_x	CO	VOC	SO_x	PM_{10}
Onsite					
Construction Equipment, Fugitive Dust	107.1	33.6	7.8	3.5	14.9
Offsite					
Truck Deliveries and Worker Travel	18.8	90.6	10.1	0.6	0.9
Total Emissions					
Total	125.9	124.2	17.9	4.1	15.8

I.2.6 Analysis of Ambient Impacts from Onsite Construction

Ambient air quality impacts from emissions during construction of the ESPR project were estimated using an air quality dispersion modeling analysis. The modeling analysis considers the construction site location, the surrounding topography, and the sources of emissions during construction, including vehicle and equipment exhaust emissions and fugitive dust.

I.2.6.1 Existing Ambient Levels

As with the modeling analysis of project operating impacts (Section 5.2.4.2.4), the Hawthorne and West Los Angeles monitoring stations were used to establish the ambient background levels for the construction impact modeling analysis. Table I.2-5 shows the maximum concentrations of NO_x, SO_2, CO, and PM_{10} recorded for 1997 through 1999 at those monitoring stations.

I.2.6.2 Dispersion Model

As in the analysis of project operating impacts, the EPA-approved Industrial Source Complex Short Term (ISCST3) model was used to estimate ambient impacts from construction activities. A detailed discussion of the ISCST3 dispersion model is included in Section 5.2.4.2.4.

Table I.2-5
Modeled Maximum Construction Impacts

Pollutant	Averaging Time	Maximum Construction Impacts (μg/m³)	Background (μg/m³)	Total Impact (μg/m³)	State Standard (μg/m³)	Federal Standard (μg/m³)
NO_x	1-Hour	225[d]	263	488	470	--
	Annual	19	53	72	--	100
SO_2	1-Hour	115 [d]	262	377	650	--
	24-Hour	13 [d]	50	63	109	365
	Annual	1	11	12	--	80
CO	1-Hour	4,129 [d]	7,778	4,907	23,000	40,000
	8-Hour	1,403 [d]	4,956	6,359	10,000	10,000
PM_{10}	24-Hour	146[e]	79	225	50	150
	Annual[b]	37	34	71	30	--
	Annual[c]	37	36	73	--	50

Notes: a. Ozone limiting method used for 1-hr average impact and ARM applied for annual average, using SCAQMD default ratio of 0.71.
b. Annual Geometric Mean.
c. Annual Arithmetic Mean.
d. Based on maximum daily emissions during Month 6.
e. Based on maximum daily emissions during Month 4.

The emission sources for the construction site were grouped into two categories: exhaust emissions and dust emissions. An effective emission plume height of 2.0 meters was used for all exhaust emissions. For construction dust emissions, an effective plume height of 0.5 meters was used in the modeling analysis. The exhaust and dust emissions were modeled as a single area source that covered the total area of the construction site. The construction impacts modeling analysis used the same receptor locations as used for the project operating impact analysis. A detailed discussion of the receptor locations is included in Section 5.2.4.2.4.

To determine the construction impacts on short-term ambient standards (24 hours and less), the worst-case daily onsite construction emission levels shown in Tables I.2-1 and I.2-2 were used. For pollutants with annual average ambient standards, the annual onsite emission levels shown in Table I.2-3 were used. As with the project operating impact analysis, the meteorological data set used for the construction emission impacts analysis is data collected at the Lennox monitoring station during 1981.

I.2.6.3 Modeling Results

Based on the emission rates of NO_x, SO_2, CO, and PM_{10} and the meteorological data, the ISCST3 model calculates hourly and annual ambient impacts for each pollutant. As mentioned above, the modeled 1-hour, 3-hour, 8-hour, and 24-hour ambient impacts are based on the worst-case daily emission rates of NO_x, SO_2, CO, and PM_{10}. The annual impacts are based on the annual emission rates of these pollutants.

The one-hour and annual average concentrations of NO_2 were computed following the revised EPA guidance for computing these concentrations (August 9, 1995 *Federal Register*, 60 FR 40465). The one-hour average impacts were adjusted using the Ozone Limiting Method. The annual average was calculated using the ambient ratio method (ARM) with the SCAQMD default value of 0.71 for the annual average NO_2/NO_x ratio.

The modeling analysis results are shown in Table I.2-5. Also included in the table are the maximum background levels that have occurred in the last three years and the resulting total ambient impacts. As shown in Table I.2-5, with the exception of 24-hour and annual PM_{10} impacts, construction impacts alone for all modeled pollutants are expected to be below the most stringent state and national standards. However, the state 24-hour and annual average PM_{10} standards are exceeded in the absence of the construction emissions for the ESPR project.

The ISCST3 model over-predicts PM_{10} construction emission impacts because of the cold plume (i.e., ambient temperature) effect of dust emissions. Most of the plume dispersion characteristics in the ISCST3 model are derived from observations of hot plumes associated with typical smokestacks. The ISCST3 model does compensate for plume temperature; however, for ambient temperature plumes, the model assumes negligible buoyancy and dispersion. Consequently, the ambient concentrations in cold plumes remain high even at significant distances from a source. The ESPR project construction site impacts are not unusual in comparison to most construction sites; construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards. The input and output modeling files are being provided electronically.

I.2.6.4 Health Risk of Diesel Exhaust

The combustion portion of annual PM_{10} emissions from Table I.2-5 above were modeled separately to determine the annual average Diesel PM_{10} exhaust concentration. This was used with the ARB-approved unit risk value of 300 in one million for a 70-year lifetime to determine the potential carcinogenic risk from Diesel exhaust during construction. The exposure was also adjusted by a factor of 1.67/70, or 0.0238, to correct for the 20-month exposure during the construction period.

The maximum modeled annual average concentration of Diesel exhaust PM_{10} in residential areas is 0.015 ug/m^3. Using the unit risk value and adjustment factors described above, the carcinogenic risk due to exposure to Diesel exhaust during construction activities is expected to be under 0.1 in one million. This is well below the 1 in one million level considered to be significant under SCAQMD Rule 1401.

I.2.6.5 Analysis of Ambient Impacts from Pipeline Construction

Construction of the natural gas, water supply, and wastewater brine pipelines will be of short duration, will require minimal equipment, and will generally occur along public roads covering a large geographical area. Therefore, the potential ambient air quality impacts associated with these construction projects are expected to be minimal.

Appendix I.2-1
DETAILED CONSTRUCTION EMISSION CALCULATIONS

Construction Equipment Daily Exhaust Emissions (Month 6)

	Equipment Rating	Units	Load Factor(1)	Number of Units	Hrs/Day Per Unit	Emission Factors (1) NOx	CO	VOC	SOx	PM10	Units	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
Air Compresssor	50	bhp	0.48	8	6.0	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	20.30	12.69	3.04	0.46	2.54
Paving Equipment	102	bhp	0.53	0	6.8	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Compactors	145	bhp	0.43	1	5.2	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	4.93	0.71	0.29	0.13	0.29
Air Compressor - gasoline	3.3	bhp	0.43	2	4.8	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.06	10.59	0.57	0.00	0.00
Plate Compactor - gasoline	4.6	bhp	0.43	2	4.8	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.08	14.76	0.80	0.00	0.00
Light Towers	15.5	bhp	0.51	2	7.0	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	1.95	1.22	0.29	0.04	0.24
Dozer	285	bhp	0.57	2	5.6	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	27.65	4.01	1.60	0.73	1.60
Backhoe	84	bhp	0.38	2	6.0	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	5.82	0.84	0.34	0.15	0.34
Loader	200	bhp	0.38	1	6.4	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	7.39	1.07	0.43	0.19	0.43
Loader	140	bhp	0.38	1	6.4	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	5.17	0.75	0.30	0.14	0.30
Motor Grader	150	bhp	0.54	1	7.2	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	8.86	1.28	0.51	0.23	0.51
Cranes, 225 Ton	350	bhp	0.43	1	5.6	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	12.81	1.86	0.74	0.34	0.74
Cranes, 150 Ton	250	bhp	0.43	2	5.6	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	18.30	2.65	1.06	0.48	1.06
Cranes, 40 Ton	185	bhp	0.43	3	4.0	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	14.51	2.10	0.84	0.38	0.84
Cranes, 20 Ton	185	bhp	0.43	1	4.0	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	4.84	0.70	0.28	0.13	0.28
Water Trucks	210	bhp	0.65	1	4.0	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	4.13	3.03	0.43	0.22	0.24
Welder - gasoline	7.5	bhp	0.45	8	5.6	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.68	117.56	6.37	0.00	0.02
Welder	23	bhp	0.45	1	6.0	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	1.09	0.68	0.16	0.02	0.14
Trucks, Fuel/Lube	210	bhp	0.65	1	4.0	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	4.13	3.03	0.43	0.22	0.24
Articulated truck	180	bhp	0.65	3	5.2	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	27.74	4.02	1.61	0.73	1.61
Flatbed	1.66	gal/hr		4	6.4	65.17	57.77	4.99	7.11	4.54	lbs/1000 gal	2.77	2.45	0.21	0.30	0.19
Truck, Concrete Pump	190	bhp	0.45	3	4.8	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	9.31	6.82	0.96	0.49	0.54
Total =												182.53	192.84	21.27	5.39	12.16

Notes:

(1) See notes on combustion emissions.

Construction Equipment Daily Exhaust Emissions (Month 4)																	
	Equipment Rating	Units	Load Factor(1)	Number of Units	Hrs/Day Per Unit	Emission Factors (1) NOx	CO	VOC	SOx	PM10	Units	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
Air Compresssor	50	bhp	0.48	5	6.0	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	12.69	7.93	1.90	0.29	1.59
Paving Equipment	102	bhp	0.53	0	6.8	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Compactors	145	bhp	0.43	1	5.2	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	4.93	0.71	0.29	0.13	0.29
Air Compressor - gasoline	3.3	bhp	0.43	2	4.8	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.06	10.59	0.57	0.00	0.00
Plate Compactor - gasoline	4.6	bhp	0.43	2	4.8	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.08	14.76	0.80	0.00	0.00
Light Towers	15.5	bhp	0.51	2	7.0	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	1.95	1.22	0.29	0.04	0.24
Dozer	285	bhp	0.57	2	5.6	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	27.65	4.01	1.60	0.73	1.60
Backhoe	84	bhp	0.38	2	6.0	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	5.82	0.84	0.34	0.15	0.34
Loader	200	bhp	0.38	1	6.4	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	7.39	1.07	0.43	0.19	0.43
Loader	140	bhp	0.38	2	6.4	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	10.35	1.50	0.60	0.27	0.60
Motor Grader	150	bhp	0.54	1	7.2	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	8.86	1.28	0.51	0.23	0.51
Cranes, 225 Ton	350	bhp	0.43	0	5.6	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Cranes, 150 Ton	250	bhp	0.43	1	5.6	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	9.15	1.33	0.53	0.24	0.53
Cranes, 40 Ton	185	bhp	0.43	3	4.0	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	14.51	2.10	0.84	0.38	0.84
Cranes, 20 Ton	185	bhp	0.43	1	4.0	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	4.84	0.70	0.28	0.13	0.28
Water Trucks	210	bhp	0.65	1	4.0	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	4.13	3.03	0.43	0.22	0.24
Welder - gasoline	7.5	bhp	0.45	4	5.6	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.34	58.78	3.19	0.00	0.01
Welder	23	bhp	0.45	1	6.0	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	1.09	0.68	0.16	0.02	0.14
Trucks, Fuel/Lube	210	bhp	0.65	1	4.0	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	4.13	3.03	0.43	0.22	0.24
Articulated truck	180	bhp	0.65	3	5.2	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	27.74	4.02	1.61	0.73	1.61
Flatbed	1.66	gal/hr		4	6.4	65.17	57.77	4.99	7.11	4.54	lbs/1000 gal	2.77	2.45	0.21	0.30	0.19
Truck, Concrete Pump	190	bhp	0.45	3	4.8	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	9.31	6.82	0.96	0.49	0.54
Total =												157.80	126.87	15.97	4.77	10.23

Notes:

(1) See notes on combustion emissions.

Construction Equipment Annual Exhaust Emissions

Equipment	Average Number of Units per Year(1)	Equipment Rating	Units	Load Factor(2)	Average Operating Hrs/Day Per Unit	Average Operating Days/Yr	Emission Factors(2) NOx	CO	VOC	SOx	PM10	Units	Annual Emissions (tons/yr) NOx	CO	VOC	SOx	PM10
Air Compresssor	8.05	50	bhp	0.48	6.0	250	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	2.56	1.60	0.38	0.06	0.32
Paving Equipment	0.40	102	bhp	0.53	6.8	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.28	0.04	0.02	0.01	0.02
Compactors	0.85	145	bhp	0.43	5.2	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.52	0.08	0.03	0.01	0.03
Air Compressor - gasoline	1.30	3.3	bhp	0.43	4.8	250	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.00	0.86	0.05	0.00	0.00
Plate Compactor - gasoline	1.15	4.6	bhp	0.43	4.8	250	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.01	1.06	0.06	0.00	0.00
Light Towers	0.70	15.5	bhp	0.51	7.0	250	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	0.09	0.05	0.01	0.00	0.01
Dozer	1.15	285	bhp	0.57	5.6	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	1.99	0.29	0.12	0.05	0.12
Backhoe	1.35	84	bhp	0.38	6.0	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.49	0.07	0.03	0.01	0.03
Loader	0.30	200	bhp	0.38	6.4	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.28	0.04	0.02	0.01	0.02
Loader	0.40	140	bhp	0.38	6.4	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.26	0.04	0.02	0.01	0.02
Motor Grader	0.50	150	bhp	0.54	7.2	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.55	0.08	0.03	0.01	0.03
Cranes, 225 Ton	0.40	350	bhp	0.43	5.6	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.64	0.09	0.04	0.02	0.04
Cranes, 150 Ton	1.20	250	bhp	0.43	5.6	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	1.37	0.20	0.08	0.04	0.08
Cranes, 40 Ton	2.15	185	bhp	0.43	4.0	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	1.30	0.19	0.08	0.03	0.08
Cranes, 20 Ton	0.65	185	bhp	0.43	4.0	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	0.39	0.06	0.02	0.01	0.02
Water Trucks	0.75	210	bhp	0.65	4.0	250	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	0.39	0.28	0.04	0.02	0.02
Welder - gasoline	10.40	7.5	bhp	0.45	5.6	250	2.03	353.00	19.13	0.00	0.06	gm/bhp-hr	0.11	19.12	1.04	0.00	0.00
Welder	2.85	23	bhp	0.45	6.0	250	8.00	5.00	1.20	0.18	1.00	gm/bhp-hr	0.39	0.24	0.06	0.01	0.05
Trucks, Fuel/Lube	0.75	210	bhp	0.65	4.0	250	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	0.39	0.28	0.04	0.02	0.02
Articulated truck	1.65	180	bhp	0.65	5.2	250	6.90	1.00	0.40	0.18	0.40	gm/bhp-hr	1.91	0.28	0.11	0.05	0.11
Flatbed	3.35	1.66	gal/hr		6.4	250	65.17	57.77	4.99	7.11	4.54	lbs/1000 gal	0.00	0.00	0.00	0.00	0.00
Truck, Concrete Pump	1.85	190	bhp	0.45	4.8	250	3.43	2.52	0.35	0.18	0.20	gm/bhp-hr	0.72	0.53	0.07	0.04	0.04
Total =													14.64	25.48	2.33	0.41	1.05

Notes:

(1) Based on average number of units operating over 20 month construction period.

(2) See notes on combustion emissions.

Delivery Truck Daily Emissions (Month 4)												
Number of Deliveries Per Day	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	
16	165.6	2649.6	0.0216	0.0158	0.0022	0.0011	0.0013	57.17	41.87	5.90	3.01	

Notes:
(1) See notes for combustion emissions.

Delivery Truck Daily Emissions (Month 6)											
Number of Deliveries Per Day(1)	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx
29	165.6	4802.4	0.0216	0.0158	0.0022	0.0011	0.0013	103.62	75.90	10.69	5.45

Notes:
(1) See notes for combustion emissions.

Delivery Truck Annual Emissions											
Average Number of Deliveries Per Year(1)	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(2) NOx	CO	VOC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	VOC	SOx
2,614	165.6	432,912	0.0216	0.0158	0.0022	0.0011	0.0013	4.67	3.42	0.48	0.25

Notes:
(1) Based on average number of truck deliveries over the 20-month construction period.
(2) See notes for combustion emissions.

Rail Delivery Daily Emissions (Month 6)

Inbound: Number of Railcars per day	Loaded Weight of Railcar (tons)	Total Gross Weight of Railcars (tons)	One-Way Haul Distance(1) (miles)	Unit Fuel Use Factor(2) (gal/KGTM)	Fuel Use (gals)	Outbound: Number of Railcars per day	Tare Weight of Railcar (tons)	Total Gross Weight of Railcars (tons)	One-Way Haul Distance(1) (miles)
4	221.5	886	100.8	1.37	122	4	34	136	100.8

Total Fuel Use (gals)	Emission Factors (lbs/1000 gals)(3) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx
141	594.71	58.59	22.03	38.00	14.76	83.93	8.27	3.11	5.36

Notes:

(1) Distance along Union Pacific Railroad line to Los Angeles County border.
(2) Based on Union Pacific Railroad system wide average fuel use factor.
(3) See notes for combustion emissions.

Rail Delivery Annual Emissions

Average Number of Rail Deliveries per Year(1)	Emissions per Delivery (lbs/rail delivery) NOx	CO	VOC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	VOC	SOx
36.6	83.93	8.27	3.11	5.36	2.08	1.54	0.15	0.06	0.10

Notes:
(1) Based on the average number of rail deliveries over the 20-month construction period.

Worker Travel Daily Emissions (Month 4)

Average Vehicle Occupancy person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(2) NOx	CO	VOC	SOx	PM10	Daily Emissions (l NOx	CO	VOC
1.16	173	165.6	28,694	0.0017	0.0176	0.0019	0.0000	0.0001	49.25	503.86	54.91

pected number of construction workers during this phase of construction.
for combustion emissions.

Worker Travel Daily Emissions (Month 6)

Average Vehicle Occupancy person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(2) NOx	CO	VOC	SOx	PM10	Daily Emissions (l NOx	CO	VOC
1.16	259	165.6	42,828	0.0017	0.0176	0.0019	0.0000	0.0001	73.51	752.02	81.95

pected number of construction workers during this phase of construction.
for combustion emissions.

Worker Travel Annual Emissions

Average Vehicle Occupancy person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Days per Year	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(2) NOx	CO	VOC	SOx	PM10	Annual E NOx	CO
1.16	215	165.6	250	8,913,491	0.0017	0.0176	0.0019	0.0000	0.0001	7.65	78.26

the average number of workers over the 20-month construction period.
for combustion emissions.

Daily Fugitive Dust Emissions (Month 4)

Equipment	Number of Units	Daily Process Rate Per Unit	Total Process Rate	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Front end loader/backhoe - excavation	5	534	2,672	cu. yds.	0.0018		4.88
Front end loader/backhoe - unpaved surface travel	5	7	36	vmt	0.1113	53%	1.88
Dozer tractor crawler - excavation	2	3	6	hours	0.7528		4.81
Grader	1	9	9	vmt	0.2754		2.60
Water trucks - unpaved surface travel	1	9	9	vmt	0.1522	53%	0.64
Concrete pump trucks - unpaved surface travel	3	2	7	vmt	0.1589	53%	0.55
Dump trucks - unloading	3	443	1,329	tons	0.0001		0.13
Dump trucks - unpaved surface travel	3	4	11	vmt	0.1589	53%	0.79
Fuel/lube truck - unpaved surface travel	1	1	1	vmt	0.1181	53%	0.05
Flatbed truck - unpaved surface travel	4	2	10	vmt	0.0803	53%	0.37
Windblown dust - active construction area	N/A	321,900	321,900	sq.ft.	0.0000	53%	3.80
Windblown dust - laydown area	N/A	291,450	291,450	sq.ft.	0.0000	53%	3.44
Windblown dust - contractor parking	N/A	261,000	261,000	sq.ft.	0.0000	53%	3.08
Workers - paved road travel	173	0.3	52	vmt	0.0005	0%	0.02
Delivery trucks - paved road travel	16	0.3	4.6	vmt	0.0185	0%	0.09
Workers - unpaved surface travel	173	0.1	10	vmt	0.0599	53%	0.28
Delivery trucks - unpaved surface travel	16	0.1	2.1	vmt	0.1589	53%	0.16
Total =							27.55

Notes:
(1) See notes for fugitive dust emission calculations.

Daily Fugitive Dust Emissions (Month 6)

Equipment	Number of Units	Daily Process Rate Per Unit	Total Process Rate	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Front end loader/backhoe - excavation	4	534	2,138	cu. yds.	0.0018		3.91
Front end loader/backhoe - unpaved surface travel	4	7	29	vmt	0.1113	53%	1.51
Dozer tractor crawler - excavation	2	3	6	hours	0.7528		4.81
Grader	1	9	9	vmt	0.2754		2.60
Water trucks - unpaved surface travel	1	9	9	vmt	0.1522	53%	0.64
Concrete pump trucks - unpaved surface travel	3	2	7	vmt	0.1589	53%	0.55
Dump trucks - unloading	3	443	1,329	tons	0.0001		0.13
Dump trucks - unpaved surface travel	3	4	11	vmt	0.1589	53%	0.79
Fuel/lube truck - unpaved surface travel	1	1	1	vmt	0.1181	53%	0.05
Flatbed truck - unpaved surface travel	4	2	10	vmt	0.0803	53%	0.37
Windblown dust - active construction area	N/A	321,900	321,900	sq.ft.	0.0000	53%	3.80
Windblown dust - laydown area	N/A	291,450	291,450	sq.ft.	0.0000	53%	3.44
Windblown dust - contractor parking	N/A	261,000	261,000	sq.ft.	0.0000	53%	3.08
Workers - paved road travel	259	0.3	78	vmt	0.0005	0%	0.04
Delivery trucks - paved road travel	29	0.3	8.3	vmt	0.0185	0%	0.15
Workers - unpaved surface travel	259	0.1	15	vmt	0.0599	53%	0.41
Delivery trucks - unpaved surface travel	29	0.1	3.8	vmt	0.1589	53%	0.28
Total =							26.54

Notes:
(1) See notes for fugitive dust emission calculations.

Annual Fugitive Dust Emissions

Activity	Average Daily PM10 Emissions(1) (lbs/day)	Days per Year	Annual PM10 Emissions (tons/yr)
Construction Activities	16.74	250	2.09
Windblown Dust	10.31	365	1.88
Total =			3.97

Notes:

(1) Based on average of daily emissions during Months 4 and 6.

Pipeline Construction Heavy Equipment Daily Emissions

Equipment	Equipment Rating	Units	Load Factor(1)	Number of Units	Hrs/Day Per Unit	Emission Factors (1) NOx	CO	VOC	SOx	PM10	Units	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
Loader	150	bhp	0.38	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	6.9	1.0	0.4	0.2	0.4
Backhoe	84	bhp	0.38	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	3.9	0.6	0.2	0.1	0.2
Crane - 20 ton	185	bhp	0.43	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	9.7	1.4	0.6	0.3	0.6
Crane - 40 ton	185	bhp	0.43	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	9.7	1.4	0.6	0.3	0.6
Dozer	265	bhp	0.57	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	18.4	2.7	1.1	0.5	1.1
Air compressor	50	bhp	0.48	1	8.0	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	3.4	2.1	0.5	0.1	0.4
Compactor	145	bhp	0.59	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	10.4	1.5	0.6	0.3	0.6
Paving machine	102	bhp	0.56	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	7.0	1.0	0.4	0.2	0.4
Grader	150	bhp	0.54	1	8.0	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	9.9	1.4	0.6	0.3	0.6
Water Truck	500	bhp	0.65	1	8.0	3.4	2.5	0.4	0.2	0.2	gm/bhp-hr	19.7	14.4	2.0	1.0	1.1
Fuel/lube truck	210	bhp	0.65	1	8.0	3.4	2.5	0.4	0.2	0.2	gm/bhp-hr	8.3	6.1	0.9	0.4	0.5
Total =												107.1	33.6	7.8	3.5	6.4

Notes:

(1) See notes for combustion emissions.

Pipeline Construction Delivery Truck Daily Emissions													
Number of Deliveries Per Day	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1)					Daily Emissions (lbs/day)				
			NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
3	165.6	496.8	0.0216	0.0158	0.0022	0.0011	0.0013	10.72	7.85	1.11	0.56	0.63

Notes:
(1) See notes for combustion emissions.

Pipeline Construction Worker Travel Daily Emissions														
Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(2)					Daily Emissions (lbs/day)				
					NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
33	1.16	28	165.6	4,711	0.0017	0.0176	0.0019	0.0000	0.0001	8.09	82.72	9.01	0.01	0.27

Notes:
(1) Based expected number of construction workers during this phase of construction.
(2) See notes for combustion emissions.

Pipeline Construction Daily Fugitive Dust Emissions					
Operation	Daily Process Rate Per Unit	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Windblown Dust	20,000	sq.ft./day	0.000025	53%	0.24
Excavation	1,426	cu.yd./day	0.0018	0%	2.61
Back filling	1,426	tons/day	0.0001	0%	0.13
Dozer	4.56	hours/day	0.7528	0%	3.43
Grader	6	vmt	0.2754	0%	1.65
Water truck unpaved surface travel	6	vmt	0.1522	53%	0.43
Delivery truck unpaved surface travel	1	vmt	0.1589	53%	0.04
Total =					8.54

Notes:
(1) See notes for fugitive dust emission calculations.

Notes - Fugitive Dust Emission Calculations

(1) Paved road travel emission factors for delivery trucks and worker automobiles are based on AP-42, Section 13.2.1, 10/97.
(Based on default road silt loading shown in AP-42, page 13.2.1-5, 10/97, limited access roads.)
(2) Wind erosion emission factor for active construction area is based on "Improvement of Specific Emission Factors (BACM Project No. 1), Final Report", prepared for South Coast AQMD by Midwest Research Institute, March 1996.
(3) Finish grading emission factor is based on AP-42, Table 11.9-1, 7/98.
(4) Bulldozer excavation emission factor is based AP-42, Table 11.9-1, 7/98.
(Based on default soil silt and moisture contents shown in AP-42, Table 11.9-3, 7/98, overburden.)
(5) Material unloading emission factors are based on AP-42, p. 13.2.4-3, 1/95.
(Based on average annual wind speed recorded at Lennox monitoring station during 1981 and default soil moisture content shown in AP-42, Table 11.9-3, 7/98, overburden.)
(6) Loader unpaved surface travel emission factor is based on AP-42, Section 13.2.2, 1/95.
(Based on default soil silt and moisture contents shown in AP-42, Table 11.9-3, 7/98, overburden.)
(7) Trenching emission factor is based on AP-42, Table 11.9-2 (dragline operations), 1/95.
(Based on default soil moisture content shown in AP-42, Table 11.9-3, 7/98, overburden.)
(8) Unpaved surface travel emission factors for water trucks, fuel trucks, service trucks, dump trucks, delivery trucks, and concrete trucks are based on AP-42, Section 13.2.2, 9/98.
(Based on default soil silt and moisture contents shown in AP-42, Table 11.9-3, 7/98, overburden.)
(9) Dust control efficiency for unpaved road travel and active excavation area is based on "Control of Open Fugitive Dust Sources", U.S. EPA, 9/88.
(Based on default evaporation rate shown in EPA document, Figure 3-2, 9/88, and typical water application rate shown in EPA document, page 3-23, 9/88.)

Notes - Combustion Emission Calculations

(1) For Construction Equipment
For heavy Diesel construction equipment, emission factors based on equipment meeting EPA 1996 off-road Diesel standards and use of CARB low-sulfur fuel.
For heavy Diesel construction equipment and portable equipment, load factors are based on EPA's "Non-road Engine and Vehicle Emission Study Report", 11/91, Table 2-05.
For trucks, depending on size of truck, emissions factors based on MVE17G version 1.0c for heavy-heavy duty or medium duty Diesel trucks, fleet average for calendar year 2002, Los Angeles County.
For portable equipment, emission factors based on EPA's "Non-road Engine and Vehicle Emission Study Report", 11/91, Table 2-07, for generator sets, welders, pumps, and air compressors less than 50

(2) For Delivery Trucks
From MVE17G version 1.0c, heavy-heavy duty Diesel trucks, fleet average for calendar year 2002, Los Angeles County.

(3) For Worker Travel
From MVE17G version 1.0c, average of light duty automobiles, fleet average for calendar year 2002, Los Angeles County.

(4) For Rail Deliveries
NOx, CO, VOC, and PM10 emission factors from EPA's "Technical Highlights - Emissions Factors for Locomotives", December 1997.
SOx emission factor from Booz-Allen & Hamilton "Locomotive Emission Study", prepared for CARB, January 1991.

APPENDIX I.3
DETAILED OPERATIONAL EMISSIONS CALCULATIONS

Table I.3.1
Baseline Units 1 to 4 Boiler Emission Calculations

Boiler	Annual Average Baseline Fuel Use (MMBtu/yr)	Maximum Heat Input Rating (MMBtu/hr)
Unit 1	2,343,655	1,785
Unit 2	1,551,048	1,785
Unit 3	8,395,178	3,417
Unit 4	9,796,056	3,417

Pollutant	Emission Factor (lbs/MMBtu)		Baseline Emissions (tons/yr) Unit 1	Unit 2	Unit 3	Unit 4	Total
CO		0.082	96.5	63.9	346.0	403.0	909.4
NOx	Emission Factor		0.127	0.111	0.052	0.017	
NOx	Emissions		149.4	86.4	218.0	81.9	535.7
PM10		0.0075	8.7	5.8	31.3	36.5	82.3
SOx		0.0006	0.7	0.5	2.5	2.9	6.6
VOC		0.0054	6.3	4.2	22.6	26.4	59.5

Notes:
1. The baseline period covers 10/98 to 9/00.
2. CO, PM10, SOx, and VOC emission factors were derived from SCAQMD Fee Form instructions (in units of lb/mmcf) and from a natural gas higher heating value of 1,020 Btu/scf (pursuant to AP-42).
3. NOx emission factor for Units 1-4 was obtained from CEMS data during calendar year 2000.

Table I.3.2
Calculation of Future Emissions for Boilers Units 3 and 4

Device	Unit 3	Unit 4
Fuel	Natural Gas	Natural Gas
Maximum Power Rating (MW)	335	335
Maximum Heat Input (MMBtu/hr)	3,417	3,417
F-factor (dscf/MMBtu)	8,710	8,710
F-factor (wscf/MMBtu)	10,610	10,610
Reference O2	3%	3%
Actual O2	5.1%	5.1%
Exhaust Temperature (F)	244	244
Exhaust Rate (dscfm @ 3% O2)	579,169	579,169
Exhaust Rate (wacfm @ actual O2)	1,065,705	1,065,705

Pollutant	Emission Factors (lb/MMBtu)	Maximum Emissions (lb/hr)		Maximum Emissions (tons/yr)		
		Unit 3	Unit 4	Unit 3	Unit 4	Total
CO	0.082	281	281	1,233	1,233	2,465
NOx	Em. Factor	0.010	0.010			
NOx	lbs/hr	33.9	33.9	148	148	297
PM10	0.0075	25.5	25.5	112	112	223
SOx	0.0006	2.01	2.01	9	9	18
VOC	0.0054	18.4	18.4	81	81	161

Pollutant	Exhaust Concentration (ppmvd @ 3% O2)	
	Unit 3	Unit 4
NOx	8.2	8.2

Notes:
1. Maximum power ratings for Units 3 and 4 provided by plant staff.
2. Heat input capacities for Units 3 & 4 estimated from their maximum power ratings and the heat rates derived for Units 1 & 2.
3. Actual O2 concentrations for Units 3 & 4 were obtained from an April 1996 source test on Unit 4 at full load.
4. Exhaust temperatures for Units 3 & 4 were obtained from an April 1996 source test on Unit 4 at full load.
5. CO, PM10, SOx, and VOC emission factors were derived from SCAQMD Fee Form instructions (in units of lb/mmcf) and from a natural gas higher heating value of 1,020 Btu/scf (pursuant to AP-42).
6. NOx emission factor for Units 3 & 4 was derived from exhaust NOx concentration, which was obtained from an April 1996 source test at full load.

Table I.3.3
Emissions and Modeling Characteristics for Fire Pump Engine

~~Fire Pump Engine~~

Manufacturer	Clarke
Model	JDFP 06WA
Maximum Output (Bhp)	265
Output During Tests (Bhp)	132.5
Fuel cons, gal/hr	14.2
Fuel cons, MMBtu/hr	1.94

	NOx	SOx (1)	CO	VOC	PM10
Emissions					
g/bhp-hr(2)	6.70	n/a	0.29	0.23	0.07
lb/hr(4)	0.98	0.050	0.04	0.03	0.01
tpy (3)	0.098	0.005	0.004	0.003	0.001

Exhaust temp	840	deg F
	721.89	deg K
Stack diam.	5	in
	0.127	m
Exh flow	1,404	acfm
	0.66	m3/s
Exh velocity	52.31	m/s

Notes:

(1) Based on 0.05 wt.% sulfur in Diesel fuel.
(2) Emission factors based on vendor information.
(3) Ton per year and annual g/s emissions calculations based on 200 hours per year of operation.
(4) Based on a 30 minute engine test at 50% engine load.

Table I.3.4a
Summary of Startup Emissions Data - pounds per hour

Project	Notes	VOC	CO	NOx	SOx	PM10
Crockett Cogeneration	Source Tests					
6/96 avg	(Notes 1 and 7)	54	46	59	-	-
6/97 avg		<1	31	41	-	-
min run		<1	27	9	-	-
max run		59	49	95	-	-
Crockett Cogeneration	FDOC (Notes 2 and 7)	170	385	160	-	-
SF Energy	FDOC (Note 7)	299	437	77	-	-
Sutter	From					
Cold Start	Westinghouse	-	838	175	-	-
Hot Start		-	902	170	-	-
Sutter	FDOC					
Cold Start	(Note 3)	1.1	838	175	2.7	9.0
Hot Start		1.1	902	170	2.7	9.0
Westinghouse	Note 4					
Cold Start		292	1722	183	3	28
Warm Start		296	1625	221	3	25
Hot Start		442	2142	217	4	33
Bechtel - DEC	From					
Cold Start	Westinghouse	437	3317	168	-	7
Hot Start	Note 5	520	7343	189	-	8
Used in AFC	Note 6					
Hot or Cold Start		2.7	100.0	35.7	1.3	11.0

Notes:
1. Minimum and maximum values are based on the six individual runs that comprise the two sets of tests.
2. Permit conditions have not been carried forward into the permit to operate, and are no longer in effect.
3. Values shown are from the engineering analysis; there are no proposed permit conditions for startup emissions limits in the FDOC.
4. Westinghouse provided data for the total plant (3 turbines) on a lbs/start basis. The above lbs/hr values were calculated assuming a 3-hour starting period per turbine for a cold start; 2 hours for a warm start; and 1 hour for a hot start. Data do not reflect the performance of oxidation catalysts or CO catalysts.
5. Bechtel estimates are 140 minutes for cold start for first engine; 40 minutes for cold start for second and third engines; and 30 minutes for hot start for each engine.
6. VOC, SOx, and PM10 values are equal to full-load emission rate. CO values are equivalent to test results for Crockett project with a safety margin added. NOx values are based on use of oversized catalyst bed.
7. Information for G.E. gas turbines.

Table I.3.4b

Summary of Startup Emissions Data – pounds per start per turbine

Project	Notes	VOC	CO	NOx	SOx	PM10
Crockett Cogeneration	Source Tests					
6/96 avg	(Notes 1 and 7)	71	62	79	-	-
6/97 avg		1	41	54	-	-
min run		<1	36	12	-	-
max run		79	66	127	-	-
Crockett Cogeneration	FDOC (Notes 2 and 7)	340	770	320	-	-
SF Energy	FDOC (Notes 3 and 7)	299	437	77	-	-
Sutter	From					
Cold Start	Westinghouse	-	611	2932	-	-
Hot Start		-	339	1804	-	-
Sutter	Proposed FDOC					
Cold Start	(Note 4)	3	2514	525	8	27
Hot Start		1	902	170	3	9
Westinghouse	Note 5					
Cold Start		875	5167	550	8	83
Warm Start		592	3250	442	5	50
Hot Start		442	2142	217	4	33
Bechtel – DEC	From					
Cold Start	Westinghouse	1019	7740	391	-	17
Hot Start		520	3671	189	-	4
Used in AFC	Note 6					
Cold Start		8.1	150.0	107.1	3.9	33.0

Notes:

1. Data extrapolated from reported hourly values by ratio of 80/60.
2. Values based on maximum two hours per startup.
3. Values based on maximum one hour per startup.
4. Values based on maximum three hours per cold start, one hour per hot start.
5. Westinghouse provided data for the total plant (3 turbines). Data do not reflect the performance of oxidation catalysts or CO catalysts.
6. Based on maximum 3-hours per startup.
7. Information for G.E. gas turbines.

Table I.35a

Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

	Base Load			Startup			NOx			SOx		CO	
							Base Load(1)	Base Load(2)	Startup	Base Load	Startup	Base Load(1)	Base L
Equipment	max. hour	hrs/day	hrs/yr	max. hour	hrs/day	hrs/yr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb
Gas Turbine 1, 83F, w/ DB, w/ PA	0	15	2099	0	0	0	22.83	18.27	0.00	1.76	0.00	33.39	11.
Gas Turbine 2, 83F, w/ DB, w/ PA	1	15	2099	0	0	0	22.83	18.27	0.00	1.76	0.00	33.39	11.
Gas Turbine 1, 83F, w/o DB, w/o PA	0	6	2099	0	0	0	15.76	12.62	0.00	1.20	0.00	23.04	7.(
Gas Turbine 2, 83F, w/o DB, w/o PA	0	6	2099	0	0	0	15.76	12.62	0.00	1.20	0.00	23.04	7.(
Gas Turbine 1, 41F, w/o DB, w/o PA	0	0	4198	0	0	0	17.54	14.04	0.00	1.36	0.00	25.65	8.5
Gas Turbine 2, 41F, w/o DB, w/o PA	0	0	4198	0	0	0	17.54	14.04	0.00	1.36	0.00	25.65	8.5
Gas Turbine 1, hot startups	0	0	0	1	0	233	0.00	0.00	35.70	0.00	1.20	0.00	0.(
Gas Turbine 2, hot startups	0	0	0	0	0	233	0.00	0.00	35.70	0.00	1.20	0.00	0.(
Gas Turbine 1, warm startups	0	0	0	0	0	96	0.00	0.00	35.70	0.00	1.20	0.00	0.(
Gas Turbine 2, warm startups	0	0	0	0	0	96	0.00	0.00	35.70	0.00	1.20	0.00	0.(
Gas Turbine 1, cold startups	0	0	0	0	3	36	0.00	0.00	35.70	0.00	1.20	0.00	0.(
Gas Turbine 2, cold startups	0	0	0	0	3	36	0.00	0.00	35.70	0.00	1.20	0.00	0.(
Unit 3 Boiler	1	24	8760	0	0	0	33.90	33.90	0.00	2.01	0.00	281.40	281
Unit 4 Boiler	1	24	8760	0	0	0	33.90	33.90	0.00	2.01	0.00	281.40	281
Fire pump engine	0	1	200	0	0	0	0.98	0.98	0.00	0.05	0.00	0.04	0.(

Notes:

(1) Short term average (i.e., for NOx less than annual average, for CO less than 30-day average).

(2) Long term average (i.e., for NOx an annual average, for CO a 30-day average).

Table I.3.5.b
Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

	NOx			SOx			CO			VOC			PM10		
	Max	Max	Total	Max	Max	Total	Max	Max	Total	Max	Max	Total	Max	Max	Total
Equipment	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy
Gas Turbine 1, 83F, w/ DB, w/ PA	0.0	342.5	19.2	1.8	26.4	1.8	0.0	500.9	11.7	6.4	95.5	6.7	15.0	225.0	15.7
Gas Turbine 2, 83F, w/ DB, w/ PA	22.8	342.5	19.2	1.8	26.4	1.8	33.4	500.9	11.7	6.4	95.5	6.7	15.0	225.0	15.7
Gas Turbine 1, 83F, w/o DB, w/o PA	0.0	94.5	13.2	0.0	7.2	1.3	0.0	138.3	8.1	0.0	15.3	2.7	0.0	66.0	11.5
Gas Turbine 2, 83F, w/o DB, w/o PA	0.0	94.5	13.2	0.0	7.2	1.3	0.0	138.3	8.1	0.0	15.3	2.7	0.0	66.0	11.5
Gas Turbine 1, 41F, w/o DB, w/o PA	0.0	0.0	29.5	0.0	0.0	2.8	0.0	0.0	17.9	0.0	0.0	6.0	0.0	0.0	23.1
Gas Turbine 2, 41F, w/o DB, w/o PA	0.0	0.0	29.5	0.0	0.0	2.8	0.0	0.0	17.9	0.0	0.0	6.0	0.0	0.0	23.1
Gas Turbine 1, hot startups	35.7	0.0	4.2	0.0	0.0	0.1	100.0	0.0	11.7	0.0	0.0	0.3	0.0	0.0	1.3
Gas Turbine 2, hot startups	0.0	0.0	4.2	0.0	0.0	0.1	0.0	0.0	11.7	0.0	0.0	0.3	0.0	0.0	1.3
Gas Turbine 1, warm startups	0.0	0.0	1.7	0.0	0.0	0.1	0.0	0.0	3.0	0.0	0.0	0.1	0.0	0.0	0.5
Gas Turbine 2, warm startups	0.0	0.0	1.7	0.0	0.0	0.1	0.0	0.0	3.0	0.0	0.0	0.1	0.0	0.0	0.5
Gas Turbine 1, cold startups	0.0	107.1	0.6	0.0	3.6	0.0	0.0	150.0	0.9	0.0	7.7	0.0	0.0	33.0	0.2
Gas Turbine 2, cold startups	0.0	107.1	0.6	0.0	3.6	0.0	0.0	150.0	0.9	0.0	7.7	0.0	0.0	33.0	0.2
Unit 3 Boiler	33.9	813.7	148.5	2.0	48.2	8.8	281.4	6,753.6	1,232.5	18.4	442.2	80.7	25.5	611.0	111.5
Unit 4 Boiler	33.9	813.7	148.5	2.0	48.2	8.8	281.4	6,753.6	1,232.5	18.4	442.2	80.7	25.5	611.0	111.5
Fire pump engine	0.0	1.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	126.3 lb/hr	2716.6 lb/day	433.9 tpy	7.5 lb/hr	170.9 lb/day	30.0 tpy	696.2 lb/hr	15,085.5 lb/day	2571.5 tpy	49.6 lb/hr	1121.5 lb/day	193.0 tpy	80.9 lb/hr	1870.1 lb/day	327.8 tpy

Assumptions:

For worst-case day, one gas turbines in startup mode for 3 hours, followed by 21 hours of base load operation.
For worst-case day, one gas turbine in startup mode for 3 hours, followed by 20 hours of base load operation (startups lag by 1 hour).
Fire pump will not be tested during gas turbine startups.

Table I.3.6.a
Calculation of RECLAIM Trading Credits

Hourly Emission Rates per Gas Turbine/HRSG	
Gas Turbine Operating Mode	NOx Emissions (lbs/hr)
83F, 100%, w DB, w PA	9.13
83F, 100%, w/o DB, w/o PA	6.33
43F, 100%, w/o DB, w/o PA	6.99
Hot Start	35.70

	NOx Emissions		
Operating Mode	Annual Operation(1) (hrs/yr)	Hourly Emission Rate (lbs/hr)	Annual Emissions (lbs/yr)
Gas Turbine 1, 83F, 100%, w DB, w PA	2,099	9.13	19,168
Gas Turbine 2, 83F, 100%, w DB, w PA	2,099	9.13	19,168
Gas Turbine 1, 83F, 100%, w/o DB, w/o PA	2,099	6.33	13,294
Gas Turbine 2, 83F, 100%, w/o DB, w/o PA	2,099	6.33	13,294
Gas Turbine 1, 41F, 100%, w/o DB, w/o PA	4,198	6.99	29,354
Gas Turbine 2, 41F, 100%, w/o DB, w/o PA	4,198	6.99	29,354
Gas Turbine 1 Startups	365	35.70	13,031
Gas Turbine 2 Startups	365	35.70	13,031
Total =			149,691
Offset Ratio =			1.0
RTCs Required =			149,691

Notes:
1. Startup emissions based on 1hr of startup per day, 365 days per year. For cold ambient, emissions based on half year at cold ambient baseload without duct burner. For hot ambient, emissions based on half year at hot ambient baseload operation (25% with duct burner, 25% without duct burner).

Table I.3.6.b
Calculation of Emission Offset Credits

Hourly Emission Rates Per Gas Turbine/HRSG

Gas Turbine Operating Mode	CO Emissions (lbs/hr)	VOC Emissions (lbs/hr)	SOx Emissions (lbs/hr)	PM10 Emissions (lbs/hr)
83F, 100%, w DB, w PA	11.12	6.37	1.76	15.00
83F, 100%, w/o DB, w/o PA	7.68	2.56	1.20	11.00
43F, 100%, w/o DB, w/o PA	8.55	2.85	1.36	11.00
Hot Start	100.00	2.56	1.20	11.00

Worst Case Month - High Ambient Temperature

		Hourly Emissions				Monthly Emissions			
Gas Turbine Operating Mode	Hours(1) Per Month	CO Emissions (lbs/hr)	VOC Emissions (lbs/hr)	SOx Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	CO Emissions (lbs/month)	VOC Emissions (lbs/month)	SOx Emissions (lbs/month)	PM10 Emissions (lbs/month)
Gas Turbine 1, 83F, 100%, w DB, w PA	496	11.12	6.37	1.76	15.00	5,516	3,159	872	7,440
Gas Turbine 2, 83F, 100%, w DB, w PA	496	11.12	6.37	1.76	15.00	5,516	3,159	872	7,440
Gas Turbine 1, 83F, 100%, w/o DB, w/o PA	217	7.68	2.56	1.20	11.00	1,667	555	261	2,387
Gas Turbine 2, 83F, 100%, w/o DB, w/o PA	217	7.68	2.56	1.20	11.00	1,667	555	261	2,387
Gas Turbine 1, Hot Starts	31	100.00	2.56	1.20	11.00	3,100	79	37	341
Gas Turbine 2, Hot Starts	31	100.00	2.56	1.20	11.00	3,100	79	37	341
Total =						20,566	7,586	2,341	20,336
Average Daily Emissions (lbs/day)(2) =						686	253	78	678
Offset Ratio(3) =						1.2	1.2	1.2	1.2
ERCs Required (lbs/day) =						823	303	94	813

Notes:
1. Based on 1 hr per day of startup, 16 hrs per day of 100% with duct burner, and 7 hrs per day of 100% without duct burner, and 31 days of operation per month.
2. Based on SCAQMD NSR rule requirement to calculate average daily emission based on 30 days per month.
3. Based on SCAQMD NSR rule offset ratio.

Table I.3.7.a El Segundo Unit 1 and Unit 2 Historical Operating Data

	Unit 1		Rolling 12-month	Unit 2		Rolling 12-month
Month	Fuel (mmcf)	Days	Op. Days	Fuel (mmcf)	Days	Op. Days
Sep-98	182	21		173	27	
Oct-98	635	27		15	1	
Nov-98	2	0		0	0	
Dec-98	0	0		0	0	
Jan-99	0	0		0	0	
Feb-99	0	0		0	0	
Mar-99	0	0		0	0	
Apr-99	188	14		19	2	
May-99	37	5		2	0	
Jun-99	44	3		64	5	
Jul-99	530	29		575	31	
Aug-99	576	29	128	356	18	84
Sep-99	699	30	137	209	10	67
Oct-99	618	30	140	449	24	90
Nov-99	126	7	147	0	0	90
Dec-99	0	0	147	0	0	90
Jan-00	0	0	147	3	0	90
Feb-00	0	0	147	0	0	90
Mar-00	0	0	147	0	0	90
Apr-00	0	0	133	0	0	88
May-00	122	5	133	397	13	101
Jun-00	173	11	141	234	14	110
Jul-00	199	11	123	178	10	89
Aug-00	512	30	124	418	25	96

Table I.3.7.b Unit 1 and 2 Shutdown Emission Reduction Credits

Period		CO (lb/day)	SOx (lb/day)	VOC (lb/day)	PM (lb/day)	Usage Factor
Sept 1998 to Aug 1999	Unit 1 Average Daily Emissions Period 1	719.7	5.1	47.1	65.1	0.5
Sept 1999 to Aug 2000	Unit 1 Average Daily Emissions Period 2	865.3	6.2	56.7	78.3	0.5
	Daily Average Unit 1 ERCs	**792.5**	**5.7**	**51.9**	**71.7**	
Sept 1998 to Aug 1999	Unit 2 Average Daily Emissions Period 1	781.2	5.6	51.2	70.7	0.5
Sept 1999 to Aug 2000	Unit 2 Average Daily Emissions Period 2	833.8	6.0	54.6	75.4	0.5
	Daily Average Unit 2 ERCs	**807.5**	**5.8**	**52.9**	**73.1**	
	Total ERCs	**1600**	**11**	**105**	**145**	

APPENDIX I.4
MODELING PROTOCOL

sierra
research

1801 J Street
Sacramento, CA 95814
(916) 444-6666
Fax: (916) 444-8373

November 3, 2000

Memo To: Yi-Hui Huang
South Coast AQMD

From: Tom Andrews

Subject: Modeling Protocol for the El Segundo Power Redevelopment Project

The purpose of this memo is to confirm our October 31, 2000 telephone conversation during which the District approved the modeling protocol for the El Segundo Power Redevelopment Project. The modeling protocol was e-mailed to the District for review and approval on October 24, 2000. The District had the following comments on the modeling protocol:

- The District wanted the protocol to clarify that while there is only one year of SCAQMD processed/approved meteorological data for the Lennox monitoring station (i.e., 1981), that station has collected data for a number of years.

- The District wanted the protocol to clarify that preliminary modeling was performed to determine how far out to place the receptor grid for the initial screening level modeling analysis.

- The District requested that "(no calms)" be added after the discussion of the "Calms processing off" modeling option.

- The District requested that since a 1981 meteorological set will be used for the modeling analysis, 1981 rather than 1996 ozone data collected at the West Los Angeles Veteran's Hospital monitoring station should be used for ozone limiting.

Enclosed for your files is a revised modeling protocol that incorporates the above District comments. In addition to the above comments, the District wanted to make sure that a toxic air pollutant impact analysis is performed for the project to meet the requirements of Rule 1401. We agree with the District that a Rule 1401 toxic air pollutant impact analysis will need to be performed for the El Segundo Redevelopment Project. We are planning on performing this analysis using the same approach as used for the Mountainview Power Company Rule 1401 analysis that was recently reviewed by the District.

If we have not characterized our telephone conversation correctly, please give us a call.

Enclosure

cc: Chris Tooker, CEC
John Yee, SCAQMD
Tom Chico, SCAQMD
Tim Hemig, NRG
Scott Magi, NRG
Tim Murphy, URS
Joan Heredia, URS

Protocol for Evaluating Ambient Air Quality Impacts for the Proposed El Segundo Power Redevelopment Project (Revised 11/2/2000)

Introduction

NRG Energy is planning to construct and operate additional electrical generation units on the site of the former SCE El Segundo Power Plant located in El Segundo, California. The existing El Segundo Power Plant consists of four natural gas fired utility boilers. The applicant is proposing to shut down two of the existing boilers and install two new GE combustion turbines, each rated at 172 megawatts (MW) (nominal) at ISO conditions, and two heat recovery steam generators (HRSG) equipped with duct burners rated at 600 MMBtu/hr (gross). Incidental equipment will include a 265 hp Diesel fire pump engine. Natural gas will be the only fuel used at the facility with the exception of the Diesel fuel used by the Diesel fire pump engine.

The proposed project will be a modification of an existing major source.

The applicant will submit an air quality impact analysis to both the South Coast Air Quality Management District (SCAQMD or District) and the California Energy Commission (CEC). The modeling analysis will include pollutants for which emissions exceed the District's NSR rule (Regulation XIII) evaluation thresholds as well as emissions of those pollutants that exceed the District's PSD Rule (Regulation XVII) thresholds (shown in Table 1). The purpose of this document is to establish the procedure for meeting the SCAQMD and CEC air quality modeling requirements for the proposed project.

Although the project area is classified as attainment for SO_2 and NO_2, both are considered nonattainment pollutants under the District NSR regulations, as they are precursors to PM_{10}. In addition, NOx is also a precursor to ozone. As a result of the above, both the NSR and PSD regulations apply to the SOx and NOx emissions associated with the project. The NSR rule requires best available control technology (BACT), modeling, and emission offsets for subject emission sources. Similar to the NSR program, Regulation XVII (PSD) also requires BACT and modeling, and it requires preconstruction ambient monitoring for facilities that trigger review. The modeling analysis required by the PSD regulation also includes performing an increment consumption analysis.

Table 1 NSR and PSD Threshold Values		
Requirement	Pollutant	Threshold
PSD Regulations		
Major Source Threshold	NOx, CO, SOx, PM_{10}, VOC	25 tons/yr*
Significant Emission Increase Threshold	NOx, CO, SOx, VOC	25 tons/yr
	PM_{10}	15 tons/yr
NSR Regulations		
BACT, Offsets, Modeling Thresholds	NOx, CO, SOx, PM_{10}, VOC	Any Net Emissions Increase from New or Modified Source

* For those sources included in the 28 source categories specified in SCAQMD Rule 1702, including steam electric generation facilities of more than 250 MMBtu/hr.

The project is expected to result in a net emission increase that will exceed the PSD significance threshold for NOx. In addition, the project is expected to result in emission increases that will trigger review under the District NSR regulations for NOx, CO, PM_{10}, SOx, and VOC. Consequently, for NOx the project will be subject to review under both the PSD and NSR regulations. The project is also expected to require CEC modeling analyses for cumulative impacts and construction impacts. Modeled ambient impacts are expected to be well below the levels at which PSD preconstruction monitoring is required. Consequently, it is not expected that onsite preconstruction monitoring will be required for the project. The results of the modeling analysis will be presented in detail in the CEC application for certification (AFC) and the application for a permit to construct.

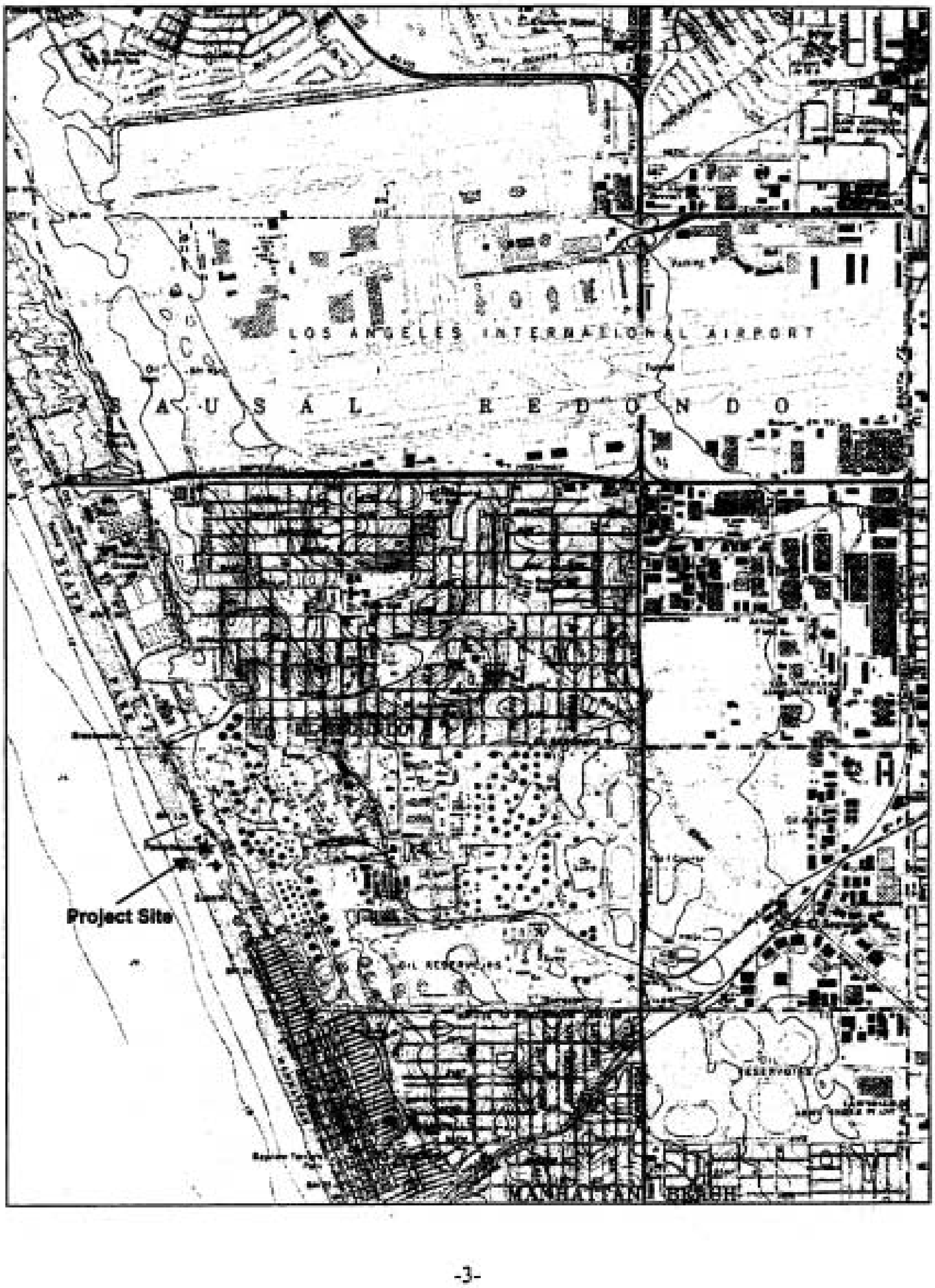
Existing Facility

As discussed above, the existing facility is comprised of four natural gas fired electric generation steam boilers. The existing Units 1 and 2 are each rated at approximately 175 MW and existing Units 2 and 4 are each rated at approximately 335 MW.

Project Location

The proposed project is located in the Coastal Region of the South Coast AQMD (Los Angeles County), approximately 2.5 miles southwest of the Los Angeles airport, on the site of the former SCE El Segundo Power Plant. The UTM coordinates of the site are approximately 368,337 meters Easting and 3,752,987 meters Northing (NAD 27). The

Figure 1
Project Location



site is located in the City of El Segundo, and the nominal site elevation is approximately 15 feet above mean sea level. The area surrounding the project site encompasses open ocean, the coastline, and a portion of urban Los Angeles, and thus can be characterized as an urban/rural mix of lands. For modeling purposes, the area will be characterized as urban, not only because it is standard SCAQMD procedure to characterize all land use in the Los Angeles basin as urban, but also because the project area is a mix of residential, commercial, and industrial land uses. The most prominent terrain feature is the coastline, which runs NNW-SSE just west of the project site. Small bluffs, roughly 100 feet high, run along the coast just east of the project site; beyond the bluffs are small hills. Elevated terrain lies some distance away - at the closest approach to the project, to the northeast, elevations rise to the proposed stack top height at 10.4 km distance.

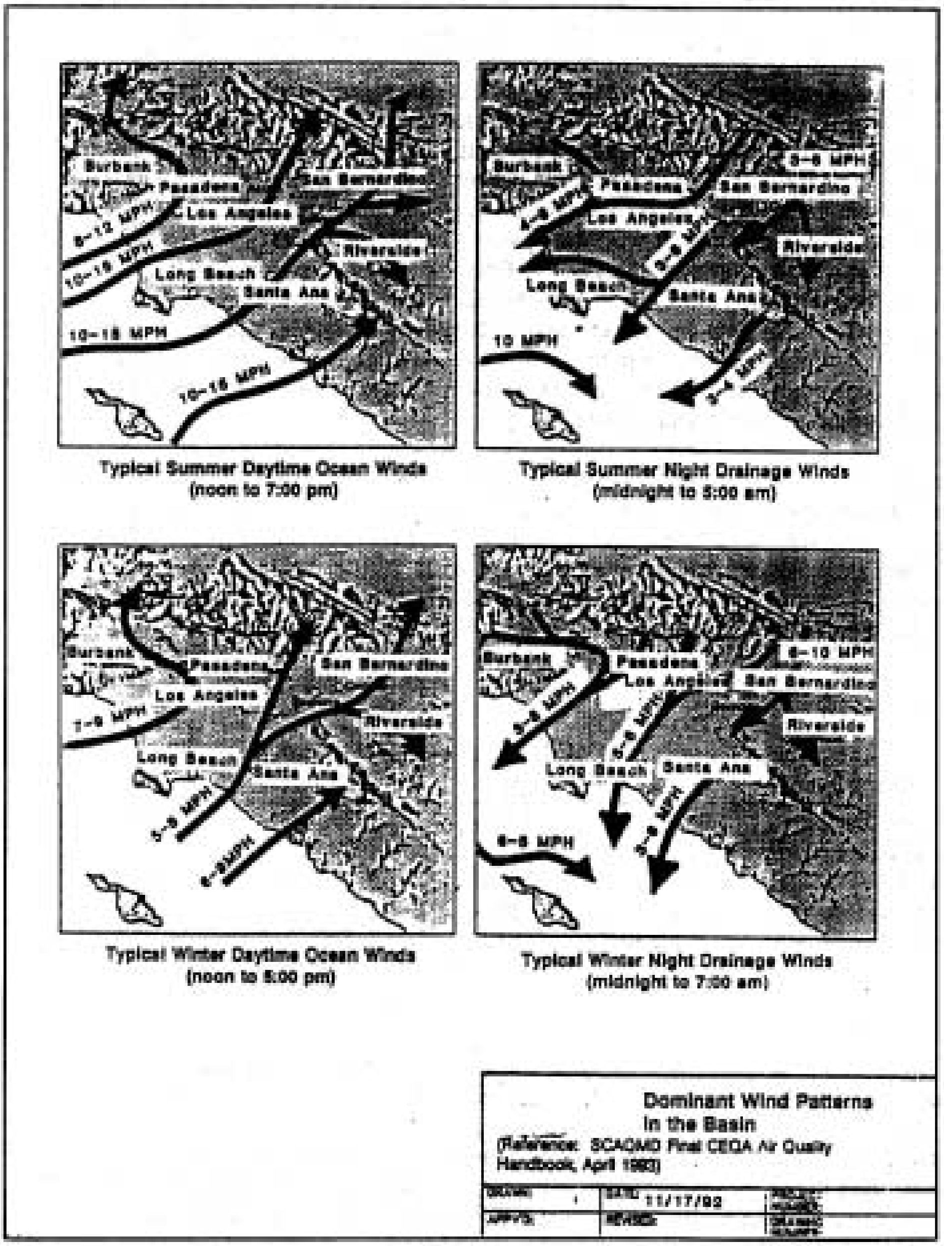
The local climate of the project area is determined primarily by proximity to the coast. California, in general, is dominated by a semi-permanent, subtropical Pacific high-pressure system. Generally mild, the climate is tempered by cool sea breezes. Apart from the inland valleys, the annual average temperature recorded at Los Angeles International Airport (LAX) of 63° F varies little throughout the air basin. The mild climate may be frequently interrupted by periods of extremely hot weather, however, during the summer and early fall months. Even at the coast, temperatures well above 100° F have been recorded. At LAX, only 3.7 km northeast of the project site, the overall minimum and maximum temperatures ever reported were 27° F (in 1949), and 110° F (in 1963), respectively. Despite a dry climate, the annual humidity averages 72% at LAX. This high relative humidity in a semi-arid climatic region is due to the presence of a shallow marine layer. The basin receives most of its rainfall between November and April; the annual average at LAX is 12.01 inches.

The dominant regional wind pattern in the Los Angeles basin is a daytime onshore breeze and a nighttime offshore breeze, which is broken frequently by passing storms or frontal systems, as well as by Santa Ana flows that occur primarily during the period of September through March. Overall, the basin experiences light average wind speeds with little seasonal variation. Generally these low wind speeds contribute to the atmosphere's limited capability to disperse air contaminants horizontally within the basin. Figure 2 shows the dominant wind patterns within the air basin. Additionally, the basin is characterized by frequent strong, elevated inversions. These inversions, created by atmospheric subsidence, severely limit vertical mixing, especially in the late morning and early afternoon periods, and allow the buildup of air pollutants by restricting their movement out of the basin.

Meteorological Data and Site Representation

EPA defines the term "on-site data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

Figure 2
Dominant Wind Patterns in the Basin



This requirement and EPA's guidance on the use of on-site monitoring data are also outlined in the On-Site Meteorological Program Guidance for Regulatory Modeling Applications (1987). The representativeness of meteorological data is dependent upon (a) the proximity of the meteorological monitoring site to the area under consideration; (b) the complexity of the topography of the area; (c) the exposure of the meteorological sensors; and (d) the period of time during which the data are collected. As discussed below, we believe that meteorological data collected at the Lennox site approximately 5 km from the project site would satisfy the definition of on-site data. While there is only one year of South Coast AQMD processed/approved data for the Lennox site, multi-year data sets from the Lennox and and other monitoring sites in the area indicate a predominant and consistent east-west wind pattern that is reproduced in the 1981 Lennox data set. Furthermore, as there are no nearby (localized) terrain features that would influence the project site, other than the large-scale terrain features that are located approximately 10 km from the project site, no site-specific bias exists that would limit the use of the Lennox data set for the proposed El Segundo project. The same large-scale topographic features that influence the Lennox meteorological site also influence the proposed project site in the same manner.

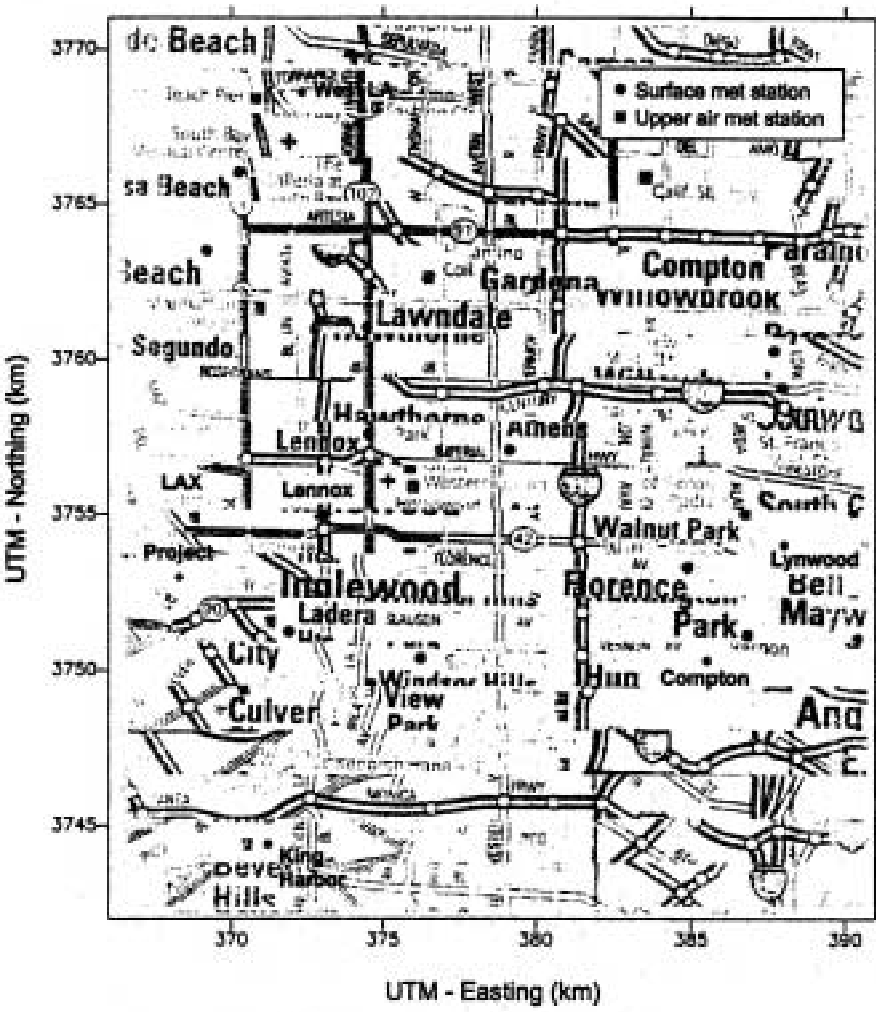
There are several meteorological stations where surface wind data (wind speed and wind direction) and upper air data have been collected, which can be used to characterize the general project area. Data for the year 1981 have been made available by SCAQMD at its website (http://www.aqmd.gov/metdata/index.html). The locations of these monitoring sites are shown in Figure 3. The station ID numbers and UTM coordinates for these sites are listed below.

Station Name	ID	UTM Easting (km)	UTM Northing (km)	Distance From Site (km)
Lennox (Surface)	52118	373.0	3755.0	5.1
King Harbor (Surface)	53012	371.2	3744.4	9.1
West LA (Surface)	52158	372.3	3768.6	16.1
Compton (Surface)	53112	385.5	3750.3	17.4
Lynwood (Surface)	52130	388.0	3754.0	19.8

The Lennox meteorological monitoring station is the closest station to the proposed project site, at 5.1 kilometers towards the east-northeast.

Diurnal wind regimes markedly affect the horizontal transport of air in the project area. Wind patterns in an area are influenced greatly by the large-scale terrain features. Given the lack of nearby large-scale terrain features in the project area, the meteorological data measured at Lennox are considered representative of the general meteorological conditions in the project area, and can correctly characterize the important atmospheric dispersion conditions at the project site.

Figure 3
Meteorological Stations in Vicinity of Project Site



Representativeness has been defined in the document "Workshop on the Representativeness of Meteorological Observations" (Nappo et. al., 1982) as "the extent to which a set of measurements taken in a space-time domain reflects the actual conditions in the same or different space-time domain taken on a scale appropriate for a specific application." Judgments of representativeness should be made only when sites are climatologically similar, as the Lennox and project site locations clearly are. Representativeness has also been defined in the PSD Monitoring Guideline as data that characterize the air quality for the general area in which the proposed project would be constructed and operated.

In determining the representativeness of the Lennox meteorological data set for use at the project site, the following considerations were addressed:

- *Aspect ratio of terrain, which is the ratio of the height of terrain to the width of the terrain at its base* - The ratio of terrain heights to base widths is constant for the terrain surrounding the project site and the Lennox meteorological site. Any larger-scale upslope/downslope flow from the larger terrain features surrounding the project site would be identified on the Lennox meteorological data set and would be representative of the El Segundo project site.

- *Slope of terrain* - The slope of the terrain in the project area is similar to the slope of terrain in the vicinity of the meteorological site. The surface roughness of the terrain in the area is also similar.

- *Ratio of terrain height to stack/plume height* - Final plume height (stack height plus plume rise) was calculated for D stability, 3 meter/second wind speed at 754 feet (estimated 250 foot stack height, 504 foot plume rise) above the stack base. At this final height, terrain effects on plume dispersion would be similar at locations throughout the regional area, and the plume would disperse in an identical manner to the dispersion conditions monitored at the Lennox site.

- *Correlation of terrain features to prevailing meteorological conditions* - The orientation of terrain in the region is identical and correlates well with the prevailing wind field in the Coastal Region. Thus, wind flow at the Lennox site would be similar to that at the project site. No local terrain features exist that would distort the local wind field.

It is our assessment that the meteorological data collected at Lennox would be identical to data collected at the project site. No terrain or other steering mechanisms exist that would have an effect on the meteorology at the project site. The surface roughness, height, and length of the large-scale terrain features are consistent throughout the area, and play a large role in the effect on the horizontal and vertical wind patterns. There is no slope or topographical aspect in the vicinity of the site that would reasonably affect the wind direction or speed. The final plume height from the proposed project will impact the highest terrain for most meteorological conditions, regardless of location.

As the overall purpose of gathering meteorological data is to collect measurements that are representative of the general state of the atmosphere in the area of interest, we believe that the Lennox meteorological data set would satisfy this requirement for the El Segundo project site. This data set would also satisfy the definition of on-site data, as defined in the PSD Monitoring Guidelines (1990) and the On-site Meteorological Program Guidance for Regulatory Modeling Applications (1987).

Preparation of the Meteorological Data Set

Meteorological data collected at Lennox in 1981, approximately 5 km northeast of the project site, are proposed to be used for the modeling of the El Segundo Power Redevelopment project. The SCAQMD has provided the data in a preprocessed form that can be used directly in the Industrial Source Complex—Short-Term, Version 3 (ISCST3) model. As the data have been preprocessed by the SCAQMD, no modifications to this data set are proposed. Mixing heights were provided in the SCAQMD data set. SCAQMD staff also coded any missing data as calm.

Ambient Air Quality Models

The ambient air quality modeling analysis will be performed in several steps. The first step will be to determine which combination of potential turbine operating loads and ambient conditions will produce the highest modeled impacts. This worst-case operating scenario for the turbines will be determined using the ISCST3 model and the 1981 Lennox meteorological data to model ambient impacts of NOx, SOx, VOC, PM_{10}, and CO under all of the potential operating cases.

Operating loads will range from minimum load to full load. Ambient conditions for evaluating turbine operations will range from 99 percentile minimum to maximum expected ambient temperatures (nominal 47° to 83°F). The Building Profile Input Program (BPIP) will be used to determine direction-specific building dimensions so that building downwash effects will be evaluated. Based on the above screening analysis, the turbine parameters, operating loads, and ambient temperatures will be selected for the refined modeling analysis. A Good Engineering Practice (GEP) analysis will also be performed for each stack.

The second step of the ambient air quality modeling analysis will be the refined modeling analysis that will evaluate the maximum modeled impacts from the proposed project, including the turbines (operating in the worst-case scenario as described above), the existing boilers, and the fire pump engine. Maximum emission rates will be identified for short-term and annual time periods for modeling (including turbine startups and shutdowns, as appropriate).

The SCREEN3 model will be used to evaluate fumigation impacts for all short-term averaging periods (24 hours or less). The methodology in EPA 454/R-92-019 (Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised) will be followed for this analysis. Combined impacts for all sources under fumigation conditions will be evaluated, based on SCAQMD modeling guidelines.

If maximum impacts are calculated in intermediate or complex terrain, then the CTSCREEN dispersion model will be used to assess these impacts if they violate standards or increments.

All modeling results will be compared to the following:

- PSD significance levels for NOx;
- PSD preconstruction monitoring trigger level for NOx;
- PSD NO_2 increments;
- Regulation XIII NSR significance levels for NO_2, CO, and PM_{10}; and
- State and federal ambient air quality standards.

Receptor Grids

Preliminary modeling for this facility, using both ISCST3 and SCREEN3, has established that maxima will be found in simple terrain, partly as a result of building-wake downwash impacts, not far from the coast. The closest intermediate terrain (established by stack top elevation) is 10.4 km away from the project, to the northeast. Preliminary SCREEN3 modeling indicates that complex- and intermediate-terrain impacts will be considerably outweighed by simple-terrain impacts.

Based on the preliminary modeling discussed above, the current plan for both the initial (screening) and final refined modeling analyses, using ISCST3, is to place receptors within 5 km of the project location to the west and north, within 4.5 km to the east, and within 4 km to the south; when farther than 1 km from the stacks, the spacing will be 180 meters, closer in it will be 60 meters. A refined grid of receptors spaced at 30 meters will be used in areas where the coarse grid analyses indicate modeled maxima will be located. Receptors will be placed at 30 meters along the facility fenceline. Digital Elevation Model (DEM) data will be used to select the receptor elevations.

All receptor grids will be expanded as necessary to obtain the maximum impacts. In particular, if SCREEN3 modeling indicates that complex- or intermediate-terrain impacts will exceed, or even approach, simple terrain impacts, the coarse receptor grid will be radically expanded as necessary.

Model Options

The ISCST3 model allows the selection of a number of options that affect model output. The regulatory default options will be used, as listed below.

- Final plume rise
- Buoyancy-induced dispersion
- Stack tip downwash
- Urban dispersion coefficients
- Calms processing off (no calms)
- Default wind profile exponents (based on urban dispersion)
- Default vertical temperature gradients

Ambient Air Quality Impact Analysis

In evaluating the impacts of the proposed project on ambient air quality, we will model the ambient impacts of the project, add those impacts to background concentrations, and compare the results to the state and federal ambient standards for SO_2, NO_2, PM_{10}, and CO.

The Ozone Limiting Method (OLM), implemented in the ISC3-OLM model, will be used to convert hourly modeled NOx concentrations to NO_2, as appropriate. One year of 1981 ozone data from the West Los Angeles Veteran's Hospital will be used in conjunction with the 1981 Lennox met data to make the correction. Preliminary modeling with these data sets indicates that ozone concentrations are high enough in this part of the Los Angeles area that virtually complete conversion of NOx to NO_2 will usually occur, at least in the daytime.

Background concentrations of SO_2 and PM_{10} will be the highest values monitored at the SCAQMD's Hawthorne monitoring station, during the last three years (1997-99). Background concentrations of CO and NO_2 will be the highest values monitored at the SCAQMD's West Los Angeles Veteran's Hospital monitoring station, during the last three years (1997-99).

In accordance with EPA guidance (40 CFR part 51, Appendix W, Sections 11.2.3.2 and 11.2.3.3), the highest modeled concentration will be used to demonstrate compliance with annual standards while the highest second-highest modeled concentrations will be used to demonstrate compliance with standards based on averaging periods of 24 hours or less.

Increments Analysis

Increments are the maximum allowable increases in concentration that are allowed to occur above baseline concentrations for each pollutant for which an increment has been established: currently NO_2, SO_2, and PM_{10}. The baseline concentrations are defined for each pollutant and averaging time, and are the ambient concentrations of each pollutant existing at the time that the first complete PSD application affecting the area is submitted. Applicable ambient significance levels and increments for SO_2, NO_2, and PM_{10} are shown in Table 2.

Table 2
PSD Ambient Impact Significance Levels and Increments (ug/m^3)

Pollutant	Averaging Time	Significance Level	Class I Increment	Class II Increment
SO_2	Annual	1	2	20
	24-hour	5	5	1
	3-hour	25	25	512
PM_{10}	Annual	1	5	17
	24-hour	5	0	30
NO_2	Annual	1	2.5	25

Federal and SCAQMD PSD regulations require that an increment analysis be performed only for pollutants with ambient impacts exceeding the significance levels show in Table 2. In the case of the proposed project, a PSD air quality impact analysis is expected to be required only for NO_2. If preliminary modeling shows that the NO_2 significance level is exceeded, a supplemental protocol will be provided to the District for any required increments analysis.

PSD Preconstruction Monitoring Requirements

Regulation XVII (PSD), Rule 1703, section (a)(D) requires an applicant's air quality analysis to contain preconstruction ambient air quality monitoring data for purposes of establishing background pollutant concentrations in the impact area of the proposed facility. However, according to Rule 1703 (a)(D), an applicant may be exempted from the requirement for preconstruction monitoring and may, at the Executive Officer's discretion, rely on existing continuous air quality monitoring data collected at District-approved monitoring stations to satisfy the requirement for preconstruction monitoring.

As discussed earlier, modeled ambient concentrations of pollutants from the modified facility are expected to be well below the preconstruction monitoring thresholds shown in Table 3.

Table 3
PSD Preconstruction Monitoring Thresholds

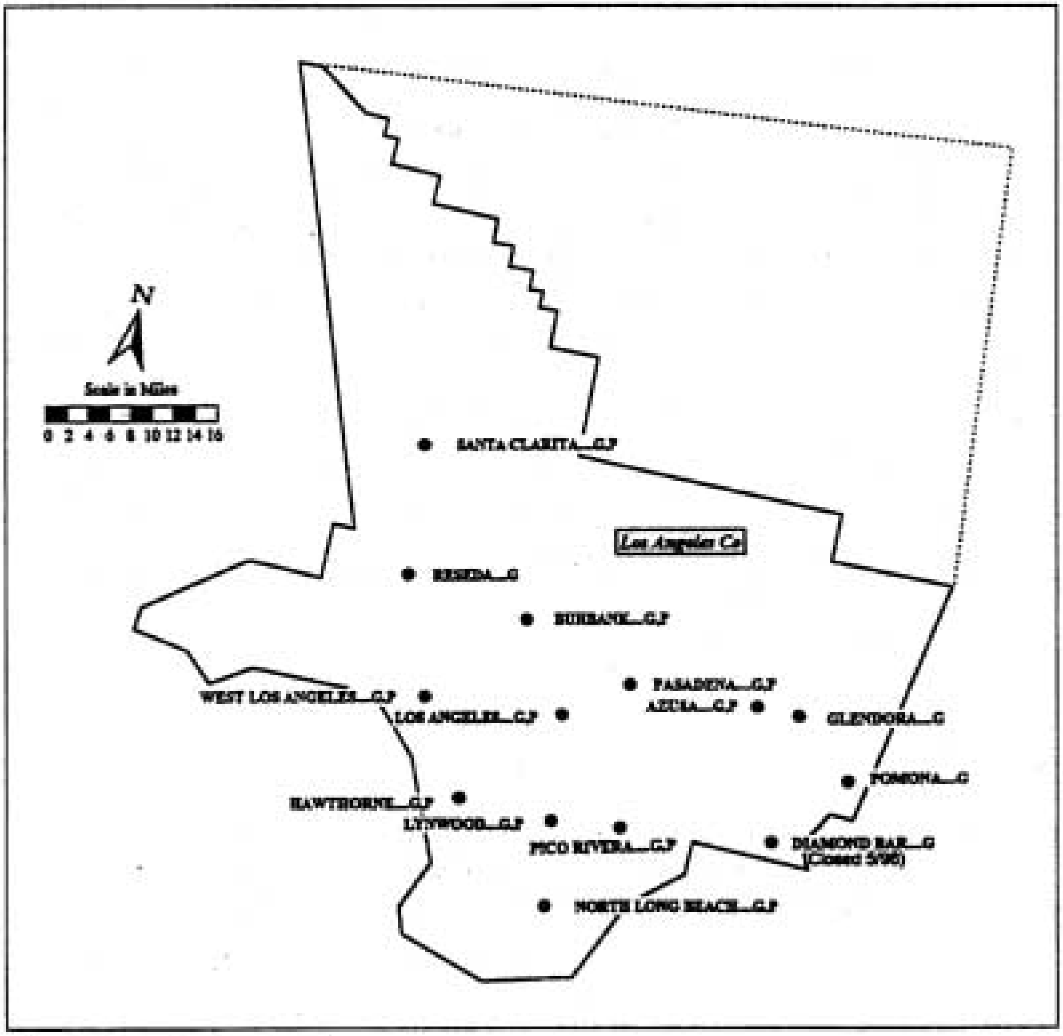
Pollutant/Averaging Time	Thresholds (ug/m^3)
CO (8-hour average)	575
PM_{10} (24-hour average)	10
NO_2 (annual average)	14
SO_2 (24-hour average)	13

If one or more of these *de minimis* levels is exceeded in the final modeling analysis, the applicant proposes to use data from the following monitoring stations to meet this requirement.

Site ID	CARB#	SCAQMD#	Pollutants
Hawthorne	3600094	094	PM10, SO_2
West LA, Vet's Hospital	3600091	091	CO, NO_2, Ozone

Figure 4 shows the approximate locations of current air quality monitoring sites in the project area.

Figure 4
Air Monitoring Sites



LEGEND:
G. Gaseous Monitoring
P...Particulate Monitoring

NSR Ambient Impact Significance Levels

The SCAQMD NSR regulation requires that a modeling analysis be performed to show that emission increases will not have a significant impact on ambient air quality. Table 4 summarizes the SCAQMD NSR significance levels per Regulation XIII, Rule 1303. The modeling analysis for the proposed project will compare maximum project impacts with the following NSR significance levels.

Table 4
SCAQMD NSR Significant Impact Levels

Pollutant	Averaging Time	Significance Levels (ug/m^3)
NO_2	Annual	1
	1-hour	20
CO	8-hour	500
	1-hour	1,100
PM_{10}	Annual*	1
	24-hour	2.5

* geometric mean value

Additional Impacts Analysis

For those pollutants emitted in significant amounts, the applicant will prepare an additional impacts analysis for growth, soils and vegetation, and visibility. Visibility impacts will be evaluated based on the criteria in Regulation XIII, Rule 1303, Appendix B.

Impacts on Class I Areas

As required by Regulations XIII and XVII, the applicant will prepare an analysis to determine whether the proposed project will result in emissions that would have an adverse impact on air quality related values, including visibility and regional haze, in Class I areas. An analysis will be conducted to determine the proposed project's impact on visibility in the following Class I areas that are within 100 km of the project site:

- Cucamonga, and
- San Gabriel

Regulation XVII also requires a demonstration that emissions from a project located within 10 km (6.2 miles) of a Class I area will not cause or contribute to the exceedance of any national ambient air quality standard or any PSD increment there. None of the above Class I areas are within 10 km of the project site.

The appropriate federal land managers (FLMs) will be contacted to obtain information on the procedures required to calculate impacts to Air Quality Related Values (AQRVs) and to determine the appropriate Levels of Acceptable Change (LAC). Impacts to visibility and regional haze at the Class I areas will be determined as well.

Additional Analyses Required by the CEC

The CEC may also require analyses of cumulative air quality impacts, construction impacts, and short-term impacts during turbine startups and during turbine commissioning. The procedures to be used in evaluating construction impacts are discussed below. If required, a separate protocol will be prepared for the cumulative impacts analysis.

<u>Construction Impacts Analysis</u>

The potential ambient impacts from air pollutant emissions during the construction of the El Segundo project will be evaluated by air quality modeling that will account for the construction site location and the surrounding topography; the sources of emissions during construction, including vehicle and equipment exhaust emissions; and fugitive dust.

<u>Site Description</u> - The dispersion modeling analysis will include a description of the physical setting of the facility and surrounding terrain. A map showing the plant location, fence lines, and model receptors will be included, as well as a plot plan of the plant site indicating heights of nearby structures above a common reference point.

<u>Types of Emission Sources</u> - Construction of the proposed El Segundo project will be divided into three main construction phases: (1) site preparation; (2) construction of foundations; and (3) installation and assembly of mechanical and electrical equipment. The construction impacts analysis will include a schedule for construction operation activities. Site preparation is expected to include site excavation, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations will begin. Once the foundations are finished, the installation and assembly of the mechanical and electrical equipment will begin.

Fugitive dust emissions from the construction of the project result from (1) dust entrained during excavation and grading at the construction site; (2) dust entrained during onsite travel on paved and unpaved roads and across the unpaved construction site; (3) dust entrained during aggregate and soil loading and unloading operations; (4) dust entrained from raw material transfer to and from material stockpiles; and (5) wind erosion of areas disturbed during construction activities. Heavy equipment exhaust emissions result from (1) the heavy equipment used for excavation, grading, and construction of onsite structures; (2) a water truck used to control construction dust emissions; (3) Diesel welding machines, gasoline-powered generators, air compressors, and water pumps; and (4) gasoline-powered pickup trucks and Diesel flatbed trucks used onsite to transport workers and materials around the construction site. Diesel and gasoline truck exhaust emissions will result from transport of mechanical and electrical equipment to the project site and transport of rubble and debris from the site to an appropriate landfill. Diesel exhaust emissions may also result from transport of raw materials to and from stockpiles.

Emissions from a worst-case day will be calculated for each of the three main construction phases and only the phase with the highest emissions will be modeled. As the construction impacts are expected to occur for a relatively short time compared with the lifetime of the project, only short-term averaging periods (24 hours or less) will be included in the construction modeling analysis.

Existing Ambient Levels - Ambient NO_2, SO_2, CO, and PM_{10} concentrations are monitored at two locations in the vicinity of the proposed site: Hawthorne monitoring station and West Los Angeles Veteran's Hospital monitoring station. These sites are believed to be representative of the site and are being proposed for use in the analysis.

Model Type - The ISCST3 model will be used to estimate ambient impacts from construction emissions. The modeling options and meteorological data described above will be used for the modeling analysis.

The construction site will be represented as an area source in the modeling analysis. Emissions will be divided into two categories: exhaust emissions and dust emissions. For exhaust emissions, a plume height of 4.6 meters (15 feet) will be used. Plume height refers to the distance measured from ground level to the center line of the emissions plume. For dust emissions, a release height of two meters will be used due to the ambient plume temperatures and negligible plume velocities.

For the construction modeling analysis, the receptor grid will begin at the property boundary and will extend approximately one kilometer in all directions. Receptor spacing will be 50 meters, with three tiers of fenceline receptors at 25 meter spacing.

Table I.5.1
Emission Rates and Stack Parameters for Screening Level Modeling (all emissions/operating data for a single new gas turbine/HRSG)

Gas Turbine/HRSG Operating Case	Ambient Temp. (deg. F)	Stack Diam (m)	Exhaust Temp. (deg. K)	Exhaust Flow (m3/s)	Exhaust Velocity (m/s)	Emission Rates, g/s 1-Hour Modeling NOx	Annual Modeling NOx	SO2	CO	PM10
Case 1 - 83F, 100% load, DB on, PA on	83	5.791	442.39	633.22	24.04	2.88	2.30	0.22	4.21	1.89
Case 2 - 83F, 100% load, DB off, PA on	83	5.791	369.00	522.01	19.82	2.18	1.74	0.17	3.18	1.39
Case 3 - 83F, 50% load, DB off, PA off	83	5.791	352.78	318.09	12.08	1.30	1.04	0.10	1.90	1.39
Case 4 - 41F, 100% load, DB off, PA off	41	5.791	368.56	524.09	19.90	2.21	1.77	0.17	3.23	1.39
Case 5 - 41F, 50% load, DB off, PA off	41	5.791	352.89	330.65	12.55	1.42	1.13	0.11	2.07	1.39

Table I.5.2
Results of Gas Turbine/HRSG Screening Analysis (combined impacts for two gas turbines/HRSGs)

Gas Turbine/HRSG Operating Case	Ambient Temp. (deg. F)	NO2 1-hr	NO2 Annual	SO2 1-hr	SO2 3-hr	SO2 24-hr	SO2 Annual	CO 1-hr	CO 8-hr	PM10 24-hr
		Modeling Impacts (ug/m3)								
Case 1 - 83F, 100% load, DB on, PA on	83	9.53	0.31	0.73	0.57	0.13	0.03	13.93	5.59	1.14
Case 2 - 83F, 100% load, DB off, PA on	83	10.04	0.41	0.78	0.69	0.17	0.04	14.64	6.61	1.36
Case 3 - 83F, 50% load, DB off, PA off	83	8.45	0.40	0.65	0.59	0.15	0.04	12.35	5.53	2.06
Case 4 - 41F, 100% load, DB off, PA off	41	10.18	0.42	0.78	0.69	0.17	0.04	14.87	6.72	1.36
Case 5 - 41F, 50% load, DB off, PA off	41	9.00	0.43	0.70	0.63	0.16	0.04	13.11	5.93	2.00

Table I.5.3 (cont.)
Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Exh Temp, Deg F
Averaging Period: Eight hours CO										
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	n/a	n/a	4.383	n/a	19.00	204
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	n/a	n/a	3.979	n/a	19.00	204
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	35.456	n/a	21.17	244
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	35.456	n/a	21.17	244
Fire Pump	0.127	721.89	0.66	52.31	n/a	n/a	0.001	n/a	0.42	840
Averaging Period: 24-hour SOx										
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	n/a	n/a	19.00	204
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	n/a	n/a	19.00	204
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	n/a	n/a	21.17	244
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	n/a	n/a	21.17	244
Fire Pump	0.127	721.89	0.66	52.31	n/a	0.000	n/a	n/a	0.42	840
Averaging Period: 24-hour PM10										
Gas Turbine 1/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.386	19.00	176
Gas Turbine 2/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.386	19.00	176
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244
Fire Pump	0.127	721.89	0.66	52.31	n/a	n/a	n/a	0.000	0.42	840

Table I.5.3 (cont.)
Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Exh Temp, Deg F
Averaging Period: Annual NOx and SOx										
Gas Turbine 1/HRSG	5.791	352.89	330.65	12.55	2.004	0.182	n/a	n/a	19.00	176
Gas Turbine 2/HRSG	5.791	352.89	330.65	12.55	2.004	0.182	n/a	n/a	19.00	176
Unit 3 Boiler	6.452	390.78	502.96	15.39	4.272	0.253	n/a	n/a	21.17	244
Unit 4 Boiler	6.452	390.78	502.96	15.39	4.272	0.253	n/a	n/a	21.17	244
Fire Pump	0.127	721.89	0.66	52.31	0.003	0.000	n/a	n/a	0.42	840
Averaging Period: Annual PM10										
Gas Turbine 1/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.507	19.00	176
Gas Turbine 2/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.507	19.00	176
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244
Fire Pump	0.127	721.89	0.66	52.31	n/a	n/a	n/a	0.000	0.42	840

Table I.5.3

Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	SO2	CO	PM10
Averaging Period: One hour NOx																
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	2.210	n/a	n/a	n/a	19.00	204	1,110,477	65.28	17.54	n/a	n/a	n/a
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	2.210	n/a	n/a	n/a	19.00	204	1,110,477	65.28	17.54	n/a	n/a	n/a
Unit 3 Boiler	6.452	390.78	502.96	15.39	4.272	n/a	n/a	n/a	21.17	244	1,065,705	50.48	33.90	n/a	n/a	n/a
Unit 4 Boiler	6.452	390.78	502.96	15.39	4.272	n/a	n/a	n/a	21.17	244	1,065,705	50.48	33.90	n/a	n/a	n/a
Fire Pump	0.127	721.89	0.66	52.31	0.123	n/a	n/a	n/a	0.42	840	1,404	171.61	0.98	n/a	n/a	n/a
Averaging Period: One hour CO and SOx																
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	3.232	n/a	19.00	204	1,110,477	65.28	n/a	1.36	25.65	n/a
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	3.232	n/a	19.00	204	1,110,477	65.28	n/a	1.36	25.65	n/a
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	35.456	n/a	21.17	244	1,065,705	50.48	n/a	2.01	281.400	n/a
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	35.456	n/a	21.17	244	1,065,705	50.48	n/a	2.01	281.400	n/a
Fire Pump	0.127	721.89	0.66	52.31	n/a	0.006	0.005	n/a	0.42	840	1,404	171.61	n/a	0.050	0.04	n/a
Averaging Period: Three hours SOx																
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	n/a	n/a	19.00	204	1,110,477	65.28	n/a	1.36	n/a	n/a
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	n/a	n/a	19.00	204	1,110,477	65.28	n/a	1.36	n/a	n/a
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	n/a	n/a	21.17	244	1,065,705	50.48	n/a	2.01	n/a	n/a
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	n/a	n/a	21.17	244	1,065,705	50.48	n/a	2.01	n/a	n/a
Fire Pump	0.127	721.89	0.66	52.31	n/a	0.002	n/a	n/a	0.42	840	1,404	171.61	n/a	0.017	n/a	n/a

Table I.5.3 (cont.)

Emission Rates and Stack Parameters for Refined Modeling

					Emission Rates, g/s								Emission Rates, lb/hr			
	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	NOx	SO2	CO	PM10	Stack Diam, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	NOx	SO2	CO	PM10
Averaging Period: Eight hours CO																
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	n/a	n/a	4.383	n/a	19.00	204	1,110,477	65.28	n/a	n/a	34.78	n/a
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	n/a	n/a	3.979	n/a	19.00	204	1,110,477	65.28	n/a	n/a	31.58	n/a
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	35.456	n/a	21.17	244	1,065,705	50.48	n/a	n/a	281.400	n/a
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	35.456	n/a	21.17	244	1,065,705	50.48	n/a	n/a	281.400	n/a
Fire Pump	0.127	721.89	0.66	52.31	n/a	n/a	0.001	n/a	0.42	840	1,404	171.61	n/a	n/a	0.01	n/a
Averaging Period: 24-hour SOx																
Gas Turbine 1/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	n/a	n/a	19.00	204	1,110,477	65.28	n/a	1.36	n/a	n/a
Gas Turbine 2/HRSG	5.791	368.56	524.09	19.90	n/a	0.171	n/a	n/a	19.00	204	1,110,477	65.28	n/a	1.36	n/a	n/a
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	n/a	n/a	21.17	244	1,065,705	50.48	n/a	2.01	n/a	n/a
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	0.253	n/a	n/a	21.17	244	1,065,705	50.48	n/a	2.01	n/a	n/a
Fire Pump	0.127	721.89	0.66	52.31	n/a	0.000	n/a	n/a	0.42	840	1,404	171.61	n/a	0.002	n/a	n/a
Averaging Period: 24-hour PM10																
Gas Turbine 1/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.386	19.00	176	673,999	39.62	n/a	n/a	n/a	11.00
Gas Turbine 2/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.386	19.00	176	673,999	39.62	n/a	n/a	n/a	11.00
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244	1,065,705	50.48	n/a	n/a	n/a	25.46
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244	1,065,705	50.48	n/a	n/a	n/a	25.46
Fire Pump	0.127	721.89	0.66	52.31	n/a	n/a	n/a	0.000	0.42	840	1,404	171.61	n/a	n/a	n/a	0.000

Table I.5.3 (cont.)

Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	SO2	CO	PM10
Averaging Period: Annual NOx and SOx																
Gas Turbine 1/HRSG	5.791	352.89	330.65	12.55	2.004	0.182	n/a	n/a	19.00	176	700,616	41.18	15.91	1.44	n/a	n/a
Gas Turbine 2/HRSG	5.791	352.89	330.65	12.55	2.004	0.182	n/a	n/a	19.00	176	700,616	41.18	15.91	1.44	n/a	n/a
Unit 3 Boiler	6.452	390.78	502.96	15.39	4.272	0.253	n/a	n/a	21.17	244	1,065,705	50.48	33.90	2.01	n/a	n/a
Unit 4 Boiler	6.452	390.78	502.96	15.39	4.272	0.253	n/a	n/a	21.17	244	1,065,705	50.48	33.90	2.01	n/a	n/a
Fire Pump	0.127	721.89	0.66	52.31	0.003	0.000	n/a	n/a	0.42	840	1,404	171.61	0.022	0.001	n/a	n/a
Averaging Period: Annual PM10																
Gas Turbine 1/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.507	19.00	176	673,999	39.62	n/a	n/a	n/a	11.960
Gas Turbine 2/HRSG	5.791	352.78	318.09	12.08	n/a	n/a	n/a	1.507	19.00	176	673,999	39.62	n/a	n/a	n/a	11.960
Unit 3 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244	1,065,705	50.48	n/a	n/a	n/a	25.460
Unit 4 Boiler	6.452	390.78	502.96	15.39	n/a	n/a	n/a	3.208	21.17	244	1,065,705	50.48	n/a	n/a	n/a	25.460
Fire Pump	0.127	721.89	0.66	52.31	n/a	n/a	n/a	0.000	0.42	840	1,404	171.61	n/a	n/a	n/a	0.000

Table I.5.4
Results of SCREEN3 Modeling for Inversion Breakup Fumigation

Receptor Location	Equipment	NO2 1-hr (ug/m3)	SO2 1-hr (ug/m3)	SO2 3-hr(1) (ug/m3)	CO 1-hr (ug/m3)	CO 8-hr(1) (ug/m3)
Maximum Gas Turbine Impacts	Single Gas Turbine/HRSG	2.13	0.16	0.14	3.12	2.18
Maximum Gas Turbine Impacts	Combined Impacts for Two Gas Turbines/HRSGs	4.26	0.32	0.29	6.23	4.36

Notes:
(1) Longer-term averages calculated from SCREEN3 modeled 1-hour averages using EPA conversion factors of 0.9 for 3-hour impacts, and 0.7 for 8-hour impacts.

NOTES TO TABLE I.5.4
FUMIGATION IMPACTS ANALYSIS

INVERSION BREAKUP FUMIGATION

Inversion breakup fumigation is generally a short-term phenomenon but was evaluated here as persisting for up to 8 hours. SCREEN3 was used to model one-hour impacts from the gas turbines/HRSGs using the full SCREEN3 meteorological dataset. The maximum inversion breakup fumigation impact for the gas turbines/HRSGs was found to occur approximately 21 kilometers from the plant site. The inversion breakup fumigation impacts for a single gas turbine/HRSG were modeled. These results were multiplied by two to calculate the maximum combined impacts for the two gas turbines/HRSGs.

One-hour impacts were adjusted for longer averaging periods using the EPA-recommended persistence factors for the SCREEN3 model, as follows:

- 3-hour average = 0.9 times 1-hour average
- 8-hour average = 0.7 times 1-hour average

Table I.5.5
Summary of Building Dimensions Used For GEP Analysis
(feet)

Building/Equipment	Length	Width	Height
Units 3 & 4 Boiler Structures (each structure)			
Tier 1	347	337	56
Tier 2	347	262	63
Tier 3	297	126	83
Tier 4	297	114	93
Tier 5a	76	108	121
Tier 5b	41	108	123
Tier 5c	76	108	121
HRSGs			
Tier 1	49	214	50
Tier 2	24	97	120
Steam Turbine Generator	40	101	50
Fire Pump Engine Building	20	20	10
Fire Water Storage Tank	40	40	40

EVALUATION OF BEST AVAILABLE CONTROL TECHNOLOGY

To evaluate BACT for the proposed gas turbines, the SCAQMD BACT guideline for large gas turbines (equipment rating greater than 3 MW) was reviewed. The relevant BACT determinations for this analysis are shown in Table I.6.1.

TABLE I.6.1
SCAQMD BACT GUIDELINE FOR LARGE GAS TURBINES

POLLUTANT	BACT
Nitrogen Oxides	(2.5 ppmv @ 15% O2) x (% efficiency/34%)
Sulfur Dioxide	No BACT level listed
Carbon Monoxide	10 ppmv @ 15% O2
VOC	No BACT level listed
NH_3	10 ppmv @ 15% O2 (1-hour average)
PM10	No BACT level listed

The EPA RACT-BACT-LAER Clearinghouse (RBLC) was also consulted to review recent EPA BACT decisions for gas-fired gas turbines. These recent BACT decisions are summarized in Table I.6.2 below. NOx levels shown in these BACT determinations are very high, although EPA has recently stated that the SCONOx technology has demonstrated that 2.5 ppm is achievable in practice. CO levels in this listing are also relatively high, and do not indicate that oxidations catalysts have been considered BACT for CO or VOCs.

The ARB's BACT Clearinghouse Database was also reviewed for recent BACT decisions regarding large gas turbine projects in California. Relevant BACT decisions are summarized in Table I.6.3. NOx levels shown in these determinations are generally around 5 ppm. None of these recent BACT decisions include a determination for CO, and the determinations for VOC include extremely low catalyst efficiencies (5 to 10 percent).

Finally, the ARB's Guidance for Power Plant Sitting and Best Available Control Technology was also reviewed. The relevant BACT levels recommended in the ARB power plant guidance document are summarized in Table I.6.4.

The Project proposes to use dry low-NOx combustors with selective catalytic reduction and oxidation catalyst technology that will achieve a NOx exhaust concentration of 2.5 ppmv or less (short term average), 2.0 ppmv (annual average), a CO exhaust concentration of 6 ppmv or less (short term average), and 2 ppmv (30-day average). The gas turbines will be fueled with natural gas to minimize SO_2 and PM_{10} emissions. VOC levels are inherently very low for the turbines (i.e., 1.4 ppmv) and while additional reduction of VOCs may occur due to the use of oxidation catalyst technology, further reductions are not needed to comply with BACT. The control systems will also achieve an ammonia slip of 5 ppmv (1-hour average). These pollutant levels will achieve emission reductions consistent with the SCAQMD BACT guideline and the ARB BACT guideline for power plants. A more detailed top down analysis for BACT for NOx and ammonia emissions is included as Attachment I.6-1.

TABLE I.6.2
GAS TURBINE BACT DETERMINATIONS FOR EPA RBLC CLEARINGHOUSE

FACILITY/LOCATION	DATE PERMIT ISSUED	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	CO LIMIT/CONTROL TECHNOLOGY
Alabama Power Company McIntosh, AL	7/10/97	100 MW combustion turbine w/ duct burner	15 ppm (dry low-NOx burners)	n/a
Lordsburg L.P. Lordsburg, NM	6/18/97	100 MW combustion turbine	15 ppm (dry low-NOx technology)	50 ppm (dry low-NOx technology)
Mead Coated Board, Inc. Phenix City, AL	3/12/97	25 MW combustion turbine w/ fired HRSG	25 ppm (dry low-NOx combustor)	28 ppm (proper design and good combustion practices)
Northern California Power Agency Lodi, CA	10/02/97	GE Frame 5 gas turbine	25 ppm	n/a
Portside Energy Corp. Portage, IN	5/13/96	63 MW gas turbine w/ unfired HRSG	n/a	10 ppm (good combustion)
Southwestern Public Service Hobbs, NM	2/15/97	Gas turbine	15 ppm w/o power augmentation 25 ppm w/ augmentation	good combustion practices

TABLE I.6.3
SUMMARY OF BACT DETERMINATIONS FROM ARB BACT CLEARINGHOUSE

FACILITY/DISTRICT	PERMIT NO.	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	VOC/HC LIMIT/CONTROL TECHNOLOGY
Sacramento Cogeneration Authority Sacramento Metropolitan AQMD	A330-849-98 A330-850-98 A330-851-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW each)	5 ppm (dry low-NOx combustion and SCR)	oxidation catalyst (10% destruction efficiency)
Sacramento Power Authority Sacramento Metropolitan AQMD	A330-852-98	Siemens V84.2 combined-cycle gas turbine w/ supplemental firing (103 MW)	3 ppm (water injection and SCR)	oxidation catalyst (5% destruction efficiency)
Carson Energy Sacramento Metropolitan AQMD	A330-854-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW)	5 ppm (water injection and SCR)	oxidation catalyst (10% destruction efficiency)
SEPCO	A330-855-98	GE Frame 7EA gas turbine w/ supplemental firing (82 MW)	5 ppm (dry low-NOx combustion and SCR)[1]	oxidation catalyst (5% destruction efficiency)

Note: 1. District indicates that applicant proposed 2.6 ppm to lower offset liability.

TABLE I.6.4
ARB BACT GUIDANCE FOR POWER PLANTS

POLLUTANT	BACT
Nitrogen Oxides	2.5 ppmv @ 15% O2 (1-hour average) 2.0 ppmv @ 15% O2 (3-hour average)
Sulfur Dioxide	Fuel sulfur limit of 1.0 grains/100 scf
Carbon Monoxide	Nonattainment areas: 6 ppmv @ 15% O2 (3-hour average) Attainment areas: District discretion
VOC	2 ppmv @ 15% O2 (3-hour average)
NH_3	5 ppmv @ 15% O2 (3-hour average)
PM10	Fuel sulfur limit of 1.0 grains/100 scf

To evaluate BACT for the proposed fire pump engine, the SCAQMD BACT guideline for emergency compression ignition engines was reviewed. The relevant BACT determinations for this analysis are shown in Table I.6.5.

TABLE I.6.5
SCAQMD BACT GUIDANCE FOR EMERGENCY COMPRESSION IGNITION ENGINES

POLLUTANT	BACT
NOx	6.9 g/bhp-hr
SOx	Fuel sulfur content of 0.05% wt. or less
CO	8.5 g/bhp-hr
VOC	1.0 g/bhp-hr
PM10	0.38 g/bh-hr

The fire pump engine will meet the BACT limits shown on Table I.6.5 with the use of low sulfur content fuel and low emission engine designs.

Attachment I.6-1

TOP DOWN ANALYSIS FOR BACT FOR NOX AND AMMONIA EMISSIONS

Top Down Analysis for BACT for NOx and Ammonia Emissions
El Segundo Power Redevelopment Project

BACT is defined in SCAQMD Rule 1302 as:

"the most stringent emission limitation or control technique which:

(1) has been achieved in practice for such category or class of source; or
(2) is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or
(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMD) or rules adopted by the District Governing Board."

Of these three "prongs" of the BACT definition, the first and third are generally controlling. This analysis will follow EPA's guidance for the preparation of "top down" BACT analyses focusing specifically on identifying emission limitations or control techniques that are achieved in practice and technically feasible.

A "top-down" analysis format, consistent with guidance provided in EPA's October 1990 Draft New Source Review Workshop Manual, has been used for the BACT analysis. That guidance lays out five steps for a top-down BACT analysis, as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls and document results
5. Select BACT

This procedure is followed for each of the two pollutants evaluated in this analysis.

1. Control of Nitrogen Oxides

a. Identify All Control Technologies

The maximum NOx emission rate for this analysis is considered to be 75 ppmvd @ 15% O_2, based on the governing new source performance standard (40 CFR 60 Subpart GG). This maximum emissions rate provides the frame of reference for the evaluation of control effectiveness and feasibility. The maximum degree of control, resulting in the minimum emission rate, is a combination of dry low-NOx combustors and either selective catalytic reduction or SCONOx to achieve a long term NOx limit of approximately 1 ppmvd. Intermediate levels of control are also evaluated.

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Potential NOx control technologies for combustion gas turbines include the following:

<u>Wet combustion controls</u>

$ Water injection
$ Steam injection

<u>Dry combustion controls</u>

$ Dry low-NOx combustor design
$ Catalytic combustors (e.g., XONON)
$ Other combustion modifications

<u>Post-combustion controls</u>

- Selective non-catalytic reduction (SNCR)
- Non-selective catalytic reduction (NSCR)
- Selective catalytic reduction (SCR)
- SCONOx

b. Eliminate Technically Infeasible Options

The performance and technical feasibility of available NOx control technologies are discussed in more detail below.

Combustion Modifications

(i) Wet Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NOx control techniques for combustion turbines. These wet injection techniques lower the flame temperature in the combustor and thereby reduce thermal NOx formation. The water or steam-to-fuel injection ratio is the most significant factor affecting the performance of wet controls. Steam injection techniques can reduce NOx emissions in gas-fired gas turbines to between 15 and 25 ppmv at 15% O_2; the practical limit of water injection has been demonstrated at approximately 25-42 ppmv @ 15% O_2 before combustor damage becomes significant. Higher diluent:fuel ratios (especially with steam) result in greater NOx reductions, but also increase emissions of CO and hydrocarbons, reduce turbine efficiency, and may increase turbine maintenance requirements. The principal NOx control mechanisms are identical for water and steam injection. Water or steam is injected into the primary combustion chamber to act as a heat sink, lowering the peak flame temperature of combustion and thus lowering the quantity of thermal NOx formed. The injected water or steam exits the turbine as part of the exhaust.

Since steam has a higher temperature/enthalpy than water, more steam is required to achieve the same quenching effect. Typical steam injection ratios are 0.5 to 2.0 pounds steam per pound fuel; water injection ratios are generally below 1.0 pound water per pound fuel. Because water has a higher heat absorbing capacity than steam (due to the temperature and to the latent heat of vaporization associated with water), it takes more steam than water to achieve an equivalent level of NOx control.

Although the lower peak flame temperature has a beneficial effect on NOx emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, CO and VOC emissions increase as water/steam-to-fuel ratios increase. Thus, the higher steam-to-fuel ratio required for NOx control will tend to cause higher CO and VOC emissions from steam-injected turbines than from water-injected turbines, due to the kinetic effect of the water molecules interfering with the combustion process. However, steam injection can reduce the heat rate of the turbine, so that equivalent power output can be achieved with reduced fuel consumption and reduced SO_2 emission rates.

Water and steam injection have been in use on both oil- and gas-fired turbines in all size ranges for many years so these NOx control technologies are clearly technologically feasible and widely available.

(ii) Dry Combustion Controls

Combustion modifications that lower NOx emissions without wet injection include lean combustion, reduced combustor residence time, lean premixed combustion and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor primary combustion zone to cool the flame, thereby reducing the rate of thermal NOx formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NOx formation.

The most advanced combination of combustion controls for NOx is referred to as dry low-NOx (DLN) combustors. DLN technology uses lean, premixed combustion to keep peak combustion temperatures low, thus reducing the formation of thermal NOx. This technology is effective in achieving NOx emission levels comparable to levels achieved using wet injection without the need for large volumes of purified water and without the increases in CO and VOC emissions that result from wet injection. Several turbine vendors have developed this technology for their engines, including the engine proposed for this project. This control technique is technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in California and commercial availability of the technology for a 200 MW GE Frame 7G natural gas-fired turbine was recently announced for one project. The combustor used in the demonstration engine is generally comparable in size to that used in GE Frame 7F engines; however, the technology has not been announced commercially for the, Frame 7F engines proposed for this project. General Electric has indicated the technology is not yet commercially available. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time; therefore, catalytic combustion controls are not available for this specific application and are not discussed further.

(iii)Post-Combustion Controls

SCR is a post-combustion technique that controls both thermal and fuel NOx emissions by reducing NOx with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NOx conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NOx combustion controls. SCR requires the consumption of a reagent (ammonia or urea), and requires periodic catalyst replacement. Estimated levels of NOx control are in excess of 90%.

Selective non-catalytic reduction (SNCR) involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1200° to 2000° F and is most commonly used in boilers. The exhaust temperature for the proposed gas turbine ranges from 1087° to 1200° F, well below the minimum SNCR operating temperature. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for this application. Even when technically feasible, SNCR is unlikely to achieve NOx reductions in excess of 80%-85%.

Nonselective catalytic reduction (NSCR) uses a catalyst without injected reagents to reduce NOx emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for this application.

SCONOx is a proprietary catalytic oxidation and absorption technology that uses a single catalyst for the removal of NOx, CO, and VOC. The catalyst simultaneously oxidizes NO, CO, and VOCs and adsorbs NO_2 onto the catalyst surface where they are stored as nitrates and nitrites. The catalyst is a monolith design, made from a ceramic substrate, with a platinum-based catalyst and a potassium carbonate coating. The SCONOx catalyst has a limited adsorption capability, and requires regeneration on a cycle of approximately 12-15 minutes.[1] Regeneration occurs by dividing the SCONOx catalyst system in a series of sealable compartments. At any point in time, approximately 20% of the compartments in a SCONOx system would be in regeneration mode, and the remaining 80% of the compartments would be in oxidation/absorption mode.[2]

Regeneration of the SCONOx catalyst must occur in an oxygen-free environment. Consequently, each SCONOx compartment is equipped with front and rear seals to isolate the compartment from the exhaust gas stream during regeneration operation.

Regeneration is accomplished by passing a gas mixture (regeneration gases) containing methane, carbon dioxide and hydrogen over the catalyst beds.[3] Regeneration gases are created using a separate, external reformer. Initial attempts to create regeneration gases from natural gas and steam within the SCONOx catalyst bed (internal autothermal regeneration) failed to produce consistent results; this technology is not being proposed by ABB Environmental at the present time.[4]

The SCONOx catalyst bed, as designed for F-class gas turbines, includes a SCOSOx catalyst (or guard bed) followed by two or more SCONOx catalysts in series. The SCOSOx catalyst is intended to remove trace quantities of sulfur-bearing compounds from the exhaust gas stream, so as to avoid poisoning of the SCONOx catalyst. Like the SCONOx catalyst, the SCOSOx catalyst is regenerated. The regeneration for the two catalyst types occurs at the same time, with the same regeneration gas supply provided to both. Regeneration gases for the SCOSOx catalyst exit the module separately from the SCONOx regeneration gases; however, both regeneration gases are returned to the gas turbine exhaust stream downstream of the SCONOx module.[5]

The external reformer used to create the regeneration gases is supplied with steam and natural gas. For one F-class turbine, an estimated 15,000 to 20,000 lbs/hr of 600°F steam is required, along with approximately 100 pounds per hour (2.2 MMbtu/hr) of natural gas.[6] To avoid poisoning the reformer catalyst, the natural gas supplied to the reformer passes through an activated carbon filter to remove sulfur-bearing compounds.[7]

To properly treat the exhaust gas without undue backpressure, an estimated 40-60 catalyst modules would be required for an F-class machine.[8] (These modules are assembled, four to a shelf, to create 10-15 shelves.) The pressure drop associated with a NOx removal efficiency

[1] Personal communication, ABB Environmental, 1/18/00.
[2] Stone & Webster, "Independent Technical Review – SCONOx Technology and Design Review", February 2000.
[3] Stone & Webster, op cit
[4] ABB Environmental, op cit
[5] ABB Environmental, op cit
[6] Ibid
[7] Stone & Webster, op cit
[8] ABB Environmental, op cit

of 90% is approximately 5” of water.[9] The estimated space velocity for such a system is 22,000/hour.[10]

The regeneration cycle time is expected to be controlled using a feedback system based on NOx emission rates.[11] That is, the higher the NOx emissions are relative to the design level, the shorter the absorption cycle, and regeneration cycles will occur more frequently. This is analogous to the use of feedback systems for controlling reagent (ammonia or urea) flow rates in an SCR system.

Maintenance requirements for SCONOx systems are expected to include periodic replacement of the reformer fuel sulfur carbon unit, periodic replacement of the reformer catalyst, periodic washings of the SCOSOx and SCONOx catalyst beds, and periodic replacement of the SCOSOx and SCONOx catalyst beds. The replacement frequency for the reformer sulfur carbon unit and reformer catalyst are unknown to NRG Energy at present. The SCOSOx catalyst is expected to require washing once per year. The lead SCONOx catalyst bed is expected to require washing once per year, while the trailing SCONOx catalyst bed(s) are expected to require washing once every three years. The annual catalyst washing process is expected to take approximately three days for an F-class machine, with an estimated annual cost of $200,000.[12] The estimated catalyst life is reported to be 7 washings[13]; the guaranteed catalyst life is 3 years[14]

The absorption operating range for the SCONOx system is 300°F to 700°F, with an optimal temperature of approximately 600°F.[15] However, regeneration cycles are not initiated unless the catalyst bed temperature is above 450°F to avoid the creation of hydrogen sulfide during the regeneration of the SCOSOx catalyst.[16]

Estimates of control system efficiency vary. ABB Environmental has indicated that the SCONOx system is capable of achieving a 90% reduction in NOx, a 90% reduction in CO to a level of 2 ppm, and an 80%-85% reduction in VOC emissions.[17] (This VOC reduction is not likely to be achieved with low VOC inlet concentrations, in the 1 – 2 ppm range.[18]) Commercially quoted NOx emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction[19], to 1.0 ppm with no averaging period

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9 Ibid
10 Ibid
11 Ibid
12 Ibid
13 Ibid
14 Letter from ABB Alstom Power to Bibb & Associates dated May 5, 2000. (ABB Three Mountain Power or ABB TMP)
15 Ibid
16 ABB Environmental, op cit. Stone & Webster, op cit
17 ABB Environmental, op cit
18 Ibid
19 ABB TMP, op cit

specified (96% reduction)[20]. The SCONOx system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device.[21]

The SCONOx system has been applied at the Sunlaw Federal Cogeneration Plant in Vernon California since December 1996, and at the Genetics Institute Facility in Massachusetts. The Sunlaw facility uses an LM-2500 gas turbine, rated at a nominal 23 MWe, and the Genetics Institute facility has a 5 MWe Solar gas turbine. The SCONOx system was proposed for use by PG&E Generating Company at its La Paloma facility; however, PG&E Generating no longer plans to use the SCONOx system at that site.[22] The SCONOx system is currently proposed for demonstration by PG&E Generating Company at the Otay Mesa Generating Project. In addition, the technology's co-developer, Sunlaw, has proposed to use the technology in conjunction with ABB gas turbines at the Nueva Azalea site in Southern California.

Based on the discussions above, the following NOx control technologies are available and potentially technologically feasible for the proposed project:

- Water injection
- Steam injection
- Dry Low-NOx Combustors
- Selective Catalytic Reduction
- SCONOx

c. Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies are ranked by NOx control effectiveness in Table 1.

Table 1
NOx Control Alternatives

NOx Control Alternative	Available ?	Technically Feasible?	NOx Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Water Injection	Yes	Yes	25-42 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	Yes	Yes	15 – 25 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency

[20] Letter from ABB Alstom Power to Sunlaw Energy Corporation dated February 11, 2000. (ABB Sunlaw)
[21] ABB Environmental, op cit
[22] Ibid

NOx Control Alternative	Available ?	Technically Feasible?	NOx Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Selective Catalytic Reduction	Yes	Yes	>90% reduction 1 – 2.5 ppm	Ammonia slip	Decreased efficiency
SCONOx	Yes[1]	Yes[2]	>90% reduction 1 – 2.5 ppm	Reduced CO; potential reduction in VOC	Decreased efficiency

Notes:
1. There are no standard, commercial guarantees for utility-scale projects for this technology available in the public domain.
2. Technology has been used on small (5 MW and 22 MW) gas turbines for a limited period of time. Has not been used on utility-scale gas turbines.

d. Evaluate Most Effective Controls and Document Results

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

The performance of SCR and SCONOx, insofar as NOx emission levels are concerned, are essentially equivalent. Both technologies have the potential to reduce NOx emissions by at least 90%, and differences between low NOx levels (1 ppm vs 2 ppm vs 2.5 ppm) appear, in the case of each technology, to be largely a function of catalyst size, turbine outlet NOx concentration, and compliance terms (e.g., averaging period).

e. Select BACT

Based on the above analysis, both SCR and SCONOx-based systems are considered, in general, to be technologically capable of achieving NOx levels below 2.5 ppm, given appropriate consideration to turbine outlet NOx levels, catalyst volume (space velocity) and control system design. For both types of systems, some provision will be necessary to accommodate short-term excursions above permit limits, and for both types of systems, particular attention to CEMS design will be necessary to ensure that low permit limits can be monitored on a continuous and accurate basis.

Based on this information, BACT for NOx is considered to be the use of either SCR or SCONOx systems to achieve NOx levels not higher than 2.5 ppm on a 1-hour average basis, or 2.0 ppm on a 3-hour average basis. The ESPR project proposes to use SCR technology to meet a NOx level of 2.5 ppm on a 1-hour average basis, and 2.0 ppm on an annual average basis with a design goal of 1 ppm on an annual basis (i.e. actual emissions). Consequently, ESPR project’s proposal is consistent with BACT requirements.

2. Control of Ammonia Emissions

a. Identify all control technologies

Ammonia emissions result from the use of ammonia-based NOx control technologies. Consequently, only an abbreviated discussion of these technologies is restated here.

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. These technologies were discussed above.

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

b. Eliminate technically infeasible options

The performance of SCR and SCONOx, insofar as NOx emission levels are concerned, has been discussed above.

c. Rank remaining control technologies by control effectiveness

SCONOx results in no emissions of ammonia, while SCR results in ammonia slip levels of up to 10 ppm. The following discussion evaluates potential ammonia slip limits of 10 ppm, 5 ppm, 2 ppm, and 0 ppm. The latter limit would be achievable, at the present time, only through the use of SCONOx technology.

d. Evaluate most effective controls and document results

SCR has been achieved in practice at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively fewer operating systems that are designed to meet low NOx permit limits of 3.0 ppm or less. Ammonia slip associated with SCR system operation results from a gradual decline in catalyst activity over time, necessitating the use of increasing amounts of ammonia injection to maintain NOx concentrations at or below the design rate.

The parameters of NOx concentration, ammonia slip limit, and catalyst life are integrally related. That is, catalyst performance is generally specified as being a particular NOx concentration (e.g., 2.5 ppm), guaranteed for N years (e.g., 3 years), with a maximum ammonia slip level of X ppm (e.g., 5 ppm). Such a specification indicates that catalyst performance will degrade over time such that at the end of three years, ammonia slip will increase to not more than 5 ppm while maintaining NOx concentrations at or below 2.5 ppm. During the early period of performance, ammonia slip from an oxidation catalyst is typically less than 1-2 ppm, and will approach the guarantee level only towards the end of the catalyst life.

Early SCR installations, as well as some later installations, have been associated with ammonia slip levels of 10 ppm. In August 1999, the California Air Resources Board adopted a BACT guideline for large gas turbines that proposed to limit ammonia slip to not more than 5 ppm. Since the 5 ppm ammonia slip level is proposed for the ESPR Project, no further discussion of the 10 ppm and 5 ppm slip levels is required.

Ammonia slip levels of 2 ppm have been required in several permits issued in the eastern United States. However, these permits have typically been associated with higher NOx levels than are proposed here. In particular, the 2 ppm ammonia slip limits have been proposed in conjunction with NOx levels that range between 2.0 and 3.5 ppm, depending on operating mode. Although ESP II is proposing a 1-hour average NOx limit of 2.5 ppm, the facility is also proposing an annual average goal of 1.0 ppm. As noted above, the SCR parameters related to NOx limits, ammonia slip, and catalyst life are all integrally related. Since no one has proposed emission limits of 2 ppm ammonia slip in conjunction with a long-term NOx average of 1.0 ppm, there is no evidence of the technical feasibility of this combination.

Finally, SCONOx has the potential to achieve this low a NOx level without any ammonia slip.

Consequently, the following discussion compares the use of SCR with a 5 ppm ammonia slip level with SCONOx to meet comparable NOx levels, but without any ammonia slip.

SCR technology is available with standard commercial guarantees with ammonia slip levels of 5 ppm and 2 ppm, in conjunction with NOx levels at least as low as 2 ppm. However, we are unaware of any commercial guarantees for NOx levels of 1 ppm and ammonia slip levels of 2 ppm.

SCR technology has been shown to be capable of achieving ammonia slip levels below 5 ppm over at least a three year catalyst life period. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

The SCAQMD’s web site lists three SCR-based BACT determinations for ammonia slip.

The earliest SCR-based BACT determination for ammonia slip listed on the SCAQMD’s web site is for the Sutter Power Project, which was approved by the Feather River AQMD in April 1999. This project is required to meet an ammonia slip limit of 10 ppm on a 3-hour average basis, in conjunction with a 2.5 ppm NOx limit on a 1-hour average basis.

The next SCR-based BACT determination for ammonia slip listed on the SCAQMD’s web site is for the La Paloma Generating project, which was approved by the San Joaquin Unified APCD in October 1999. This project is required to meet a 10 ppm ammonia slip limit on a 24-hour average basis in conjunction with a 2.5 ppm NOx limit on a 1-hour average basis.

The third SCR-based BACT determination for ammonia slip listed on the SCAQMD's web site is for the Sithe Energy Mystic facility, which was approved by the Massachusetts Department of Environmental Protection (Mass DEP) in January 2000. This project is required to comply with a 2 ppm ammonia slip limit on a 1-hour average basis in conjunction with a 2 ppm NOx limit, 1-hour average basis. The Sithe Mystic facility is also required to evaluate the availability, reliability, and cost of technologies that eliminate ammonia slip emissions, in accordance with the terms of a Memorandum of Understanding between the project operator and Mass DEP.

These permits indicate that, as recently as one year ago, ammonia slip limits of 10 ppm were considered best available control technology. The rapid changes during the last year is indicative of increasing confidence of SCR system vendors in sustaining low ammonia slip rates in conjunction with low NOx emission rates. However, none of the facilities listed are attempting to meet a long-term NOx level of 1.0 ppm. Since many of the physical system characteristics associated with lower ammonia slip rates (increased catalyst size and particular attention to control system logic design) are the same characteristics that ESP II has sought to achieve a long-term NOx level of 1.0 ppm, one would logically expect extremely low ammonia slip levels as well. However, given the lack of any real-world demonstration of these low NOx and ammonia slip levels at the present time, BACT for ammonia slip using SCR-based controls is considered to be 5 ppm for this project.

Consequently, if an SCR-based control system is selected, BACT for ammonia slip should be an emission limit of 5 ppm.

Since SCONOx technology to eliminate ammonia slip may be technologically feasible, a further evaluation of the cost/effectiveness of this technology was performed. In this analysis, the cost of a SCONOx system was compared with the cost of an SCR and oxidation catalyst system, with the incremental cost assigned to the benefit of eliminating ammonia slip emissions. (It is appropriate to make such an assignment because the performance of the SCR and oxidation catalyst systems are comparable to that proposed for SCONOx with respect to NOx and CO emission levels for this project.)

As shown in Tables 2A through 2D, the results of this analysis indicate that the incremental cost/effectiveness of the SCONOx system for the purpose of reducing ammonia emissions is nearly $50,000 per ton.

The South Coast AQMD no longer publishes cost/effectiveness criteria for use in performing BACT analyses. In the absence of SCAQMD-specific criteria, the following values are presented to provide a reference for the calculated cost/effectiveness of SCONOx as an ammonia control device. Since ammonia is regulated as a precursor to PM_{10}, the values shown below represent the BACT cost/effectiveness thresholds for PM_{10}:

Bay Area AQMD -	$5,300 /ton
San Joaquin Valley Unified APCD -	$5,700 /ton

While these values are not, by themselves, determinative, they indicate that the cost/effectiveness of using SCONOx to eliminate ammonia emissions is well in excess of costs that are normally required for the control of PM_{10} in BACT determinations in areas of California that exceed the state and/or federal PM_{10} air quality standards.

e. Select BACT

Based on the above information, BACT for ammonia is considered to be an ammonia slip limit of 5 ppm. SCONOx has the potential to eliminate ammonia emissions; however, this candidate technology was rejected for the reasons discussed above.

The ESPR project proposes to use SCR technology to meet an ammonia slip limit of 5 ppm in conjunction with NOx levels of 2.5 ppm on a 1-hour average basis and 2.0 ppm on an annual average basis, with a design goal of achieving 1.0 ppm NOx on an annual average basis. Consequently, ESP II's proposal is consistent with BACT requirements for ammonia emissions.

Table 2A

SCR Costs (per gas turbine/HRSG)

Description of Cost			Cost Factor			Cost ($)	Notes
Direct Capital Costs (DC):							
Purchased Equip. Cost (PE):							
Basic Equipment:							
Auxiliary Equipment: HRSG tube/fin modifications							
Instrumentation: SCR controls							
Ammonia storage system:							
Taxes and freight:							
PE Total:						$1,620,000	1
Direct Install. Costs (DI):							
Foundation & supports:			0.08	PE		$129,600	2
Handling and erection (included in PE cost):						$0	1
Electrical (included in PE cost):						$0	1
Piping (included in PE cost):						$0	1
Insulation (included in PE cost):						$0	1
Painting (included in PE cost):						$0	1
DI Total:						$129,600	
Site preparation for ammonia tanks						$10,000	1
DC Total (PE+DI):						$1,759,600	
Indirect Costs (IC):							
Engineering:			0.10	PE		$162,000	2
Construction and field expenses:			0.05	PE		$81,000	2
Contractor fees:			0.10	PE		$162,000	2
Start-up:			0.02	PE		$32,400	2
Performance testing:			0.01	PE		$16,200	2
Contingencies:			0.05	PE		$81,000	1
IC Total:						$534,600	
Less: Capital cost of initial catalyst charge						-$975,000	
Total Capital Investment (TCI = DC + IC):						$1,319,200	
Direct Annual Costs (DAC):	0.5 hr/SCR per			hr/yr:	4,380		
Operating Costs (O):	sched. (hr/day)	24	day/week: 7	wk/yr:	52		
Operator:	hr/shift:	1.0	operator pay ($/hr):	39.20		$42,806	2
Supervisor:	15% of operator					$6,421	2
Maintenance Costs (M): 0.5 hr/SCR per shift							
Labor:	hr/shift:	1.0	labor pay ($/hr):	39.2		$42,806	2
Material:	% of labor cost:	100%				$42,806	2
Utility Costs:							
Perf. loss:	(kwh/unit):	347.6					1
Electricity cost	($/kwh):	0.0336	Performance loss cost penalty:			$102,311	5
Ammonia	based on 153 lbs/hr of 24.5% wt aqueous ammonia, $0.05/lb					$73,883	1, 4
Catalyst replace:	based on 3 year catalyst life					$325,000	1
Catalyst dispose:	based on 2,750 ft^3 catalyst, $15/$ft^3$, 3 yr. Life					$13,750	1
Total DAC:						$649,784	
Indirect Annual Costs (IAC):							
Overhead:	60% of O&M					$80,904	2
Administrative:			0.02	TCI		$26,384	2
Insurance:			0.01	TCI		$13,192	2
Property tax:			0.01	TCI		$13,192	2
Total IAC:						$133,672	
Total Annual Cost (DAC + IAC):						$783,456	
Capital Recovery (CR):							
Capital recovery:	interest rate (%):	10					
	period (years):	15	0.1315			$173,440	2
Total Annualized Costs						$956,897	

Table 2B

Oxidation Catalyst Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/fin modifications			
Instrumentation: oxidation cat. Controls			
Taxes and freight:			
PE Total:		$725,000	1
Direct Install. Costs (DI):			
Foundation & supports:	0.08 PE	$58,000	2
Handling and erection (included in PE cost):		$0	1
Electrical (included in PE cost):		$0	1
Piping (included in PE cost):		$0	1
Insulation (included in PE cost):		$0	1
Painting (included in PE cost):		$0	1
DI Total:		$58,000	
DC Total (PE+DI):		$783,000	
Indirect Costs (IC):			
Engineering:	0.10 PE	$72,500	2
Construction and field expenses:	0.05 PE	$36,250	2
Contractor fees:	0.10 PE	$72,500	2
Start-up:	0.02 PE	$14,500	2
Performance testing:	0.01 PE	$7,250	2
Contingencies:	0.05 PE	$36,250	1
IC Total:		$239,250	
Less: Capital cost of initial catalyst charge		-$350,000	
Total Capital Investment (TCI = DC + IC):		$672,250	
Direct Annual Costs (DAC):	hr/yr: 4,380		
Operating Costs (O): sched. (hr/day 24 — day/week: 7	wk/yr: 52		
Operator: hr/shift: 0.0 — operator pay ($/hr):	39.20	$0	2
Supervisor: 15% of operator		$0	2
Maintenance Costs (M): 0.5 hr/oxidation cat. per shift			
Labor: hr/shift: 0.0 — labor pay ($/hr):	39.2	$0	2
Material: % of labor cos 100%		$0	2
Utility Costs:			
Perf. loss: (kwh/unit): 172.5			1
Electricity cost ($/kwh): 0.0336 — Performance loss cost penalty:		$50,773	5
Catalyst replace: based on 3 yr. Life		$116,667	1
Catalyst dispose: based on 240 ft^3 catalyst, $15/$ft^3$, 3 yr. Life		$1,200	1
Total DAC:		$168,640	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$0	2
Administrative:	0.02 TCI	$13,445	2
Insurance:	0.01 TCI	$6,723	2
Property tax:	0.01 TCI	$6,723	2
Total IAC:		$26,890	
Total Annual Cost (DAC + IAC):		$195,530	
Capital Recovery (CR):			
Capital recovery factor (CRF): interest rate (%): 10			
period (years): 15	0.1315	$88,383	2
Total Annualized Costs		$283,913	

Table 2C

SCONOx Cost and Cost/Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
Direct Capital Costs			
	Capital (less cost of initial catalyst charge)	$3,900,000	3, 7
	Installation	$1,700,000	3
Indirect Capital Costs			
	Engineering	$200,000	3
	Contingency	$250,000	3
	Other	-	
Total Capital Investment		$6,050,000	
Direct Annual Costs			
	Maintenance	$250,000	3
	Ammonia	-	3
	Steam/Natural Gas	$400,000	3
	Pressure Drop	$226,000	3
	Catalyst Replacement (based on 3-yr catalyst life)	$3,033,333	7, 8
	Catalyst Disposal	$0	
Total Direct Annual Costs		$3,909,333	
Indirect Annual Costs			
	Overhead	-	3
	Administrative, Tax & Insurance	$225,000	3
Total Indirect Annual Costs		$225,000	
TOTAL ANNUAL COST		$4,134,333	
Capital Recovery Factor		0.1315	2
Capital Recovery		$795,416	
TOTAL ANNUALIZED COSTS		$4,929,750	

SCONOx Ammonia Cost Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
SCONOx Annualized Costs		$4,929,750	
SCR Annualized Costs		$956,897	
Oxidation Cat. Annualized Costs		$283,913	
SCR/Oxidation Cat. Annualized Costs		$1,240,809	
Incremental Annualized Costs		$3,688,940	
Annual Ammonia Emissions with SCR (tons/yr)		74.02	6
Annual Ammonia Emissions with SCONOx (tons/yr)		0	
Reduction in Ammonia Emissions (tons/yr)		74.02	
SCONOx COST EFFECTIVENESS ($/ton removed)		$49,836	

Table 2D

Notes: SCONOx Ammonia Cost Effectiveness Analysis

Note No.	Source
1	Based on information from Duke/Fluor Daniel.
2	From EPA/OAQPS Control Cost Manual. EPA-450/3-90-006. January 1990.
3	From April 12, 2000 letter from ABB Alstom Power to Matt Haber EPA Region IX (SCONOx capital cost of $13,000,000).
4	Based on anhydrous ammonia cost of $450/ton.
5	Based on current average price of power in the project area.
6	Based on G.E. 7FA Gas Turbine/HRSG operating at 100% load, 43 deg. F ambient, duct burner on, ammonia slip of 5 ppm @ 15% O_2, operating 24 hours per day, 365 days per year.
7	Based on information from May 8, 2000 "Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project", cost of replacement catalyst for SCONOx is 70% of initial capital investment.
8	Based on information from May 5, 2000 letter from ABB Alstom Power to Bibb and Associates indicating that SCONOx catalyst life is guaranteed for a 3-year period.

APPENDIX I.7
CUMULATIVE IMPACTS ANALYSIS PROTOCOL

CUMULATIVE IMPACTS ANALYSIS PROTOCOL

Potential cumulative air quality impacts that might be expected to occur, resulting from the Project and other reasonably foreseeable projects, are both regional and localized in nature. These cumulative impacts will be evaluated as follows.

Regional Impacts

Regional air quality impacts are possible for pollutants such as ozone, which involve photochemical processes that can take hours to occur. The Project will be required to provide emissions offsets (mitigation) for ozone precursors at a 1.2 to 1.0 ratio for VOC emissions and a 1.0 to 1.0 ratio for NOx emissions. Additional mitigation may be required by the CEC.

Although the relative importance of VOC and NOx emissions in ozone formation differs from region to region, and from day to day, most air pollution control plans in California require roughly equivalent controls (on a ton-per-year basis) for these two pollutants. The change in emissions of the sum of these pollutants, equally weighted, will be able to provide a rough estimate of the impact of the project on ozone levels. The net change in emissions of ozone precursors from the project will be compared with emissions from all sources within Los Angeles County and the South Coast Air Basin as a whole.

Air quality impacts of fine particulate, or PM_{10}, have the potential to be either regional or localized in nature. On a regional basis, an analysis similar to that presented above for ozone will be performed, looking at the three pollutants that can form PM_{10} in the atmosphere, VOC, SOx, and NOx, as well as at directly emitted particulate matter. SCAQMD regulations will require offsets to be provided for PM_{10} emissions from the project at a ratio of 1.2 to 1.0. Additional mitigation may be required by the CEC.

As in the case of ozone precursors, emissions of PM_{10} precursors are expected to have approximately equivalent ambient impacts in forming PM_{10} per ton of emissions on a regional basis. A table will be provided that compares the net change in emissions of PM_{10} precursors from the project with emissions from all sources within Los Angeles County and the South Coast Air Basin as a whole.

Localized Impacts

Localized impacts from the Project could result from emissions of carbon monoxide, oxides of nitrogen, sulfur oxides, and directly emitted PM_{10}. A dispersion modeling analysis of potential cumulative air quality impacts will be performed for all four of these pollutants.

In evaluating the potential cumulative localized impacts of the Project in conjunction with the impacts of existing facilities and facilities not yet in operation but that are reasonably foreseeable, a potential impact area in which cumulative localized impacts could occur will first be identified. In order to ensure that other projects that might have significant cumulative impacts in conjunction with the project are identified, a search area with a radius of 10 km from the project site will be used for the cumulative impacts analysis.

Within this search area, three categories of projects with combustion sources will be used as criteria for identification:

- Projects that are existing and have been in operation since at least 1999.
- Projects for which air pollution permits to construct have been issued and that began operation after 1999.
- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

Projects that are existing and have been in operation since at least 1999 will be reflected in the ambient air quality data that are being used to represent background concentrations; consequently, no further analysis of the emissions from this category of facilities will be performed. The cumulative impacts analysis adds the modeled impacts of selected facilities to the maximum measured background air quality levels, thus ensuring that these existing projects are accounted for.

Projects for which air pollution permits to construct have been issued but that were not operational by 1999 will be identified through a request of permit records from SCAQMD. The search will be requested for new or modified emission sources located within 10 km of the project site that have net emission increases greater than 10 lbs/day for CO, NOx, SOx, or PM_{10}. Projects that satisfy this criteria and that had a permit to construct issued after January 1, 1999, will be included in the cumulative air quality impacts analysis. The January 1, 1999 date was selected based on the typical length of time a permit to construct is valid and typical project construction times to ensure that projects that are not reflected in the 1999 ambient air quality data are included in the analysis.

A list of projects within the area for which air pollution permits to construct have not yet been issued, but that are reasonably foreseeable, will also be requested from the SCAQMD staff.

Given the potentially wide geographic area over which the dispersion modeling analysis is to be performed, the ISCST3 model will be used to evaluate cumulative localized air quality impacts. The detailed modeling procedures, ISCST3 options, and meteorological data used in the cumulative impacts dispersion analysis will be the same as those used in the ambient air quality impacts analyses for the Project. The receptor grid will be spaced at 180 meters and will cover the area in which the detailed modeling analysis performed for the Project indicates the project will have impacts that exceed the PSD significance levels.

Cumulative Impacts Dispersion Modeling

The dispersion modeling analysis of cumulative localized air quality impacts for the proposed project will be evaluated in combination with other reasonably foreseeable projects and air quality levels attributable to existing emission sources, and the impacts will be compared to state or federal air quality standards for significant impact. As discussed above, the highest second-highest modeled concentrations will be used to demonstrate compliance with standards based on short-term averaging periods (24 hours or less).

Supporting information will be provided, including the following:

- 1997 emissions inventory for Los Angeles County and the South Coast Air Basin;
- List of projects resulting from the screening analysis of permit files by the SCAQMD;
- Map showing locations of sources included in the cumulative air quality impacts dispersion modeling analysis;
- Stack parameters for sources included in the cumulative air quality impacts dispersion modeling analysis; and
- Output files for the dispersion modeling analysis.

APPENDIX I.8
ERC INFORMATION

EL SEGUNDO POWER REDEVELOPMENT
APPLICATION FOR CERTIFICATION

ERC INFORMATION

ENCLOSURE A
(NON - CONFIDENTIAL)

ATTACHMENT 1

TO

ENCLOSURE A

APPENDIX I-9
SCREENING HEALTH RISK ASSESSMENT
ESPR PROJECT

SCREENING HEALTH RISK ASSESSMENT
ESPR PROJECT

The health risk assessment was conducted in accordance with the procedures developed by the California Air Pollution Control Officers' Association (CAPCOA) in the Air Toxics "Hot Spots" Program: Revised 1992 Risk Assessment Guidelines, CAPCOA, (1993). The screening risk assessment evaluated the future operation of the new turbines, the existing boilers and the Diesel fire pump for the proposed ESPR Project.

The screening health risk assessment was carried out in three steps. First, emissions of noncriteria pollutants were calculated for sources associated with the ESPR Project. Noncriteria pollutant emissions from the turbines, boilers and Diesel fire pump engine are summarized in Tables 5.16-1, 5.16-2 and 5.16-3.

Next, the ISCST3 model was used with unit emission rates for each source to calculate the contribution of each source to total concentration at each receptor. This was done using a refined receptor grid. Maximum impacts of each compound for each source were calculated using the emission rates in the tables below and the modeled unit impacts; the results of these calculations are shown in Table 5.16-4. Stack parameters for the Diesel fire pump that was included in the HRA are shown in Appendix I, Table I.3.3.

Finally, the most current available OEHHA acute and chronic reference exposure levels and cancer unit risk values were used with the ARB's HRA model to evaluate acute, chronic and carcinogenic risks through inhalation pathways. As the HRA model does not account for hexane or Diesel particulate, these compounds were added to the chronic and carcinogenic risk assessments manually. Cancer risks for individual compounds were adjusted to account for multipathway exposure using multipathway adjustment factors developed in the ARB's HRA model.[1] Enclosed as Attachment 5.16-1 are copies of the HRA model input and output files.

In accordance with draft ARB guidance on risk assessments for Diesel-fueled engines, Diesel exhaust particulate matter has been used as a surrogate for all toxic air contaminant emissions from Diesel-fueled engines in determining cancer risk and noncancer hazard index for these sources.

[1] Note that the mothers' milk pathway is erroneously excluded from the calculation of 70-year individual cancer risk in the HRA model. This calculation was corrected by using the multipathway adjustment factor from the 44-year exposure calculation when calculating the carcinogenic risk from exposure to PAHs.

The locations of the three highest acute, carcinogenic and chronic exposures for the project are shown in Figures 5.16-1 and 5.16-2. As this figure shows, the location of the maximum modeled carcinogenic impact is different for the gaseous pollutants, emitted principally by the turbines and boilers, from the location of the maximum impact of the particulate matter emitted by the small, Diesel-fueled fire pump. The modeling results show that the maximum modeled carcinogenic risk from the project is expected to be 0.9 in one million. SCAQMD Rule 1401 sets significance levels of one in one million for

Table 5.16-1
Noncriteria Pollutant Emissions from the Gas Turbines

	Calculated Emissions, Each Turbine/HRSG			Emission Rates for Modeling, Each Turbine/HRSG	
Compound	Emission Factor, lb/MMscf[1]	Emissions, lb/hr[2]	Emissions, tpy[3]	One-hour Average, g/s	Annual Average, g/s
Acetaldehyde*	6.86E-2	0.168	0.59	2.11E-2	1.71E-2
Acrolein *	6.43E-3[4]	1.57E-2	5.57E-2	1.98E-3	1.60E-3
Ammonia	--	16.9[5]	74.1[6]	2.13	2.13
Benzene*	1.36E-2	3.32E-2	0.12	4.19E-3	3.39E-3
1,3-Butadiene*	1.27E-4	3.10E-4	1.10E-2	3.91E-5	3.17E-5
Ethylbenzene*	1.79E-2	4.38E-2	0.16	5.51E-3	4.46E-3
Formaldehyde*	1.10E-1	0.269	0.95	3.39E-2	2.74E-2
Hexane*	2.59E-1	0.633	2.25	7.98E-2	6.46E-2
Naphthalene*	1.66E-3	4.05E-3	1.44E-2	5.11E-4	4.14E-4
PAHs	6.60E-4	1.61E-3	5.72E-3	2.03E-4	1.65E-4
Propylene	7.70E-1	1.88	6.68	2.37E-1	1.92E-1
Propylene Oxide*	4.78E-2	0.117	0.41	1.47E-2	1.19E-2
Toluene*	7.10E-2	0.174	0.62	2.19E-2	1.77E-2
Xylene*	2.61E-2	6.38E-2	0.23	8.04E-3	6.51E-3
Total HAPs, two turbines			10.8		

Notes: * indicates Hazardous Air Pollutant (HAP).

1. Emission factors from CATEF database, except as noted.
2. Based on maximum hourly gas turbine fuel use of 2.44 MMscf/hr.
3. Based on maximum annual gas turbine fuel use of 17,338.9 MMscf/yr.
4. A review of the CATEF database showed that only one of the gas turbines tested was an engine comparable to the units proposed for the project. The emission factor is the average of three test results for this unit.
5. Maximum hourly NH_3 emissions based on 5 ppm ammonia slip from SCR, 100% load, 83 deg. F operating case, w/ duct burner.
6. Maximum annual NH_3 emissions based on maximum hourly emission rate and 8760 hours per year of operation (including startup periods).

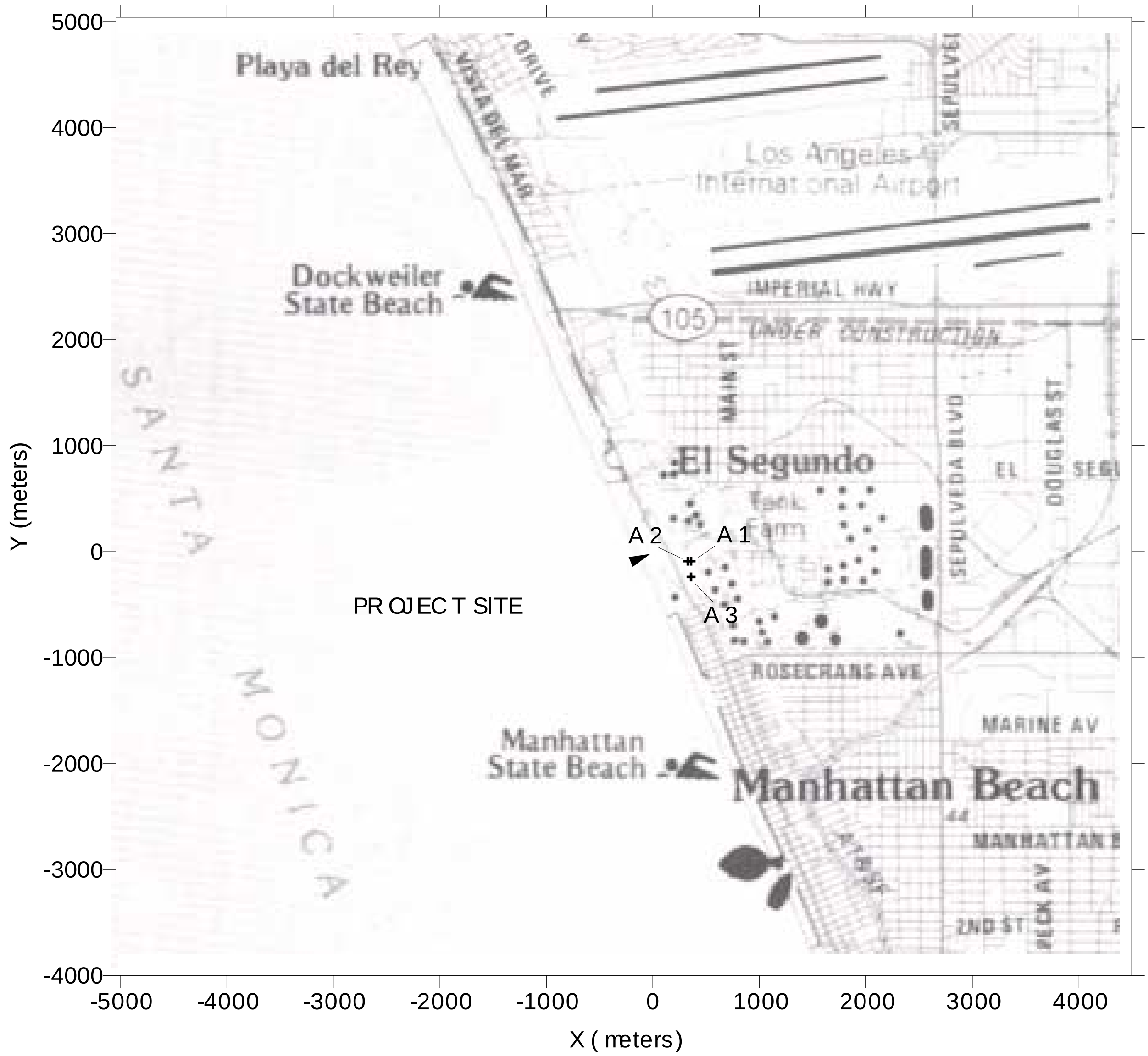

Figure 5.16-1
Maximum Acute Impacts

KEY

A1 = Highest Acute Impact
A2 = 2nd Highest Acute Impact
A3 = 3rd Highest Acute Impact

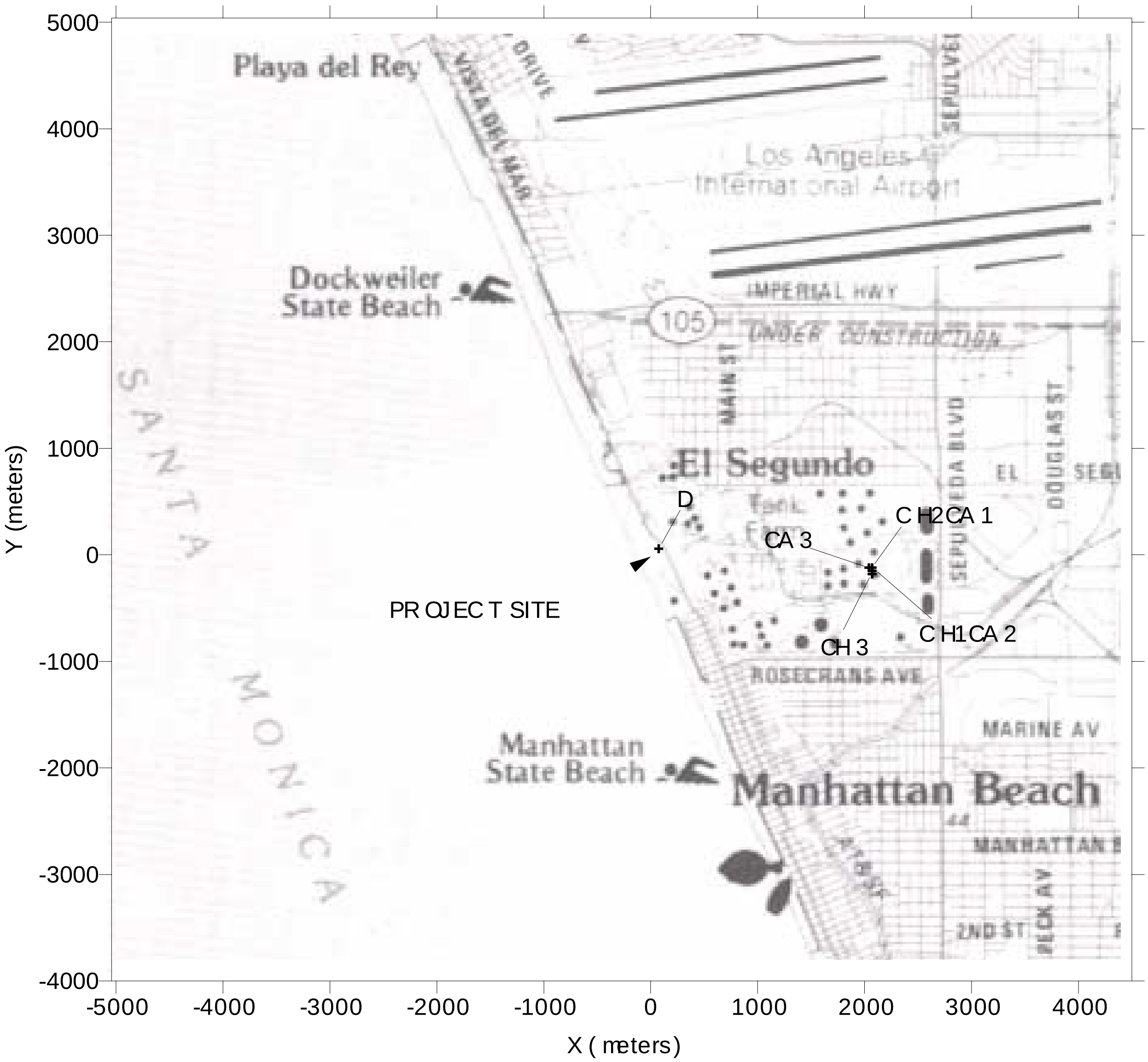

Figure 5.16-2

Maximum Chronic & Carcinogenic Impacts

KEY

D = Highest Diesel Particulate Impact

CH1 = Highest Cancer Impact

CH2 = 2nd Highest Cancer Impact

CH3 = 3rd Highest Cancer Impact

CA1 = Highest Chronic Impact

CA2 = 2nd Highest Chronic Impact

CA3 = 3rd Highest Chronic Impact

projects that do not use Toxics Best Available Control Technology (TBACT) and ten in one million for projects that do use TBACT. The proposed project will include oxidation catalysts on both turbines/HRSGs, and oxidation catalyst technology is generally considered TBACT for these sources. However, since the carcinogenic risk for the project is below one in one million the risk is not considered significant.

The chronic and acute noncarcinogenic hazard indices for the project are 0.02 and 0.01, respectively. Both are well below the significant impact level of one.

Table 5.16-2
Noncriteria Pollutant Emissions from the Boilers (Future Operation)

	Calculated Emissions, Each Boiler			Emission Rates for Modeling, Each Boiler	
Compound	Emission Factor, lb/MMscf[1]	Emissions, lb/hr[2]	Emissions, tpy[3]	One-hour Average, g/s	Annual Average, g/s
Acetaldehyde*	8.90E-3	2.98E-2	0.13	3.76E-3	3.76E-3
Acrolein *	8.00E-4	2.68E-3	1.17E-2	3.38E-4	3.38E-4
Ammonia	--	17.3[4]	75.8[5]	2.18	2.18
Benzene*	4.31E-3	1.44E-2	6.32E-2	1.82E-3	1.82E-3
1,3-Butadiene*	--	--	--	--	--
Ethylbenzene*	2.00E-2	6.70E-2	0.29	8.44E-3	8.44E-3
Formaldehyde*	2.21E-1	0.74	3.24	9.33E-2	9.33E-2
Hexane*	1.30E-3	4.36E-3	1.91E-2	5.49E-4	5.49E-4
Naphthalene*	3.00E-4	1.01E-3	4.40E-3	1.27E-4	1.27E-4
PAHs	4.00E-4	1.34E-3	5.87E-3	1.69E-4	1.69E-4
Propylene	1.55E-1	0.52	2.27	6.54E-2	6.54E-2
Propylene Oxide*	--	--	--	--	--
Toluene*	7.80E-3	2.61E-2	0.11	3.29E-3	3.29E-3
Xylene*	5.80E-3	1.94E-2	8.51E-2	2.45E-3	2.45E-3

Notes: * indicates Hazardous Air Pollutant (HAP).

1. Emission factors from Ventura County APCD and CATEF databases, except as noted.
2. Based on maximum hourly gas turbine fuel use of 3.35 MMscf/hr.
3. Based on maximum annual gas turbine fuel use of 29,346 MMscf/yr.
4. Maximum hourly NH_3 emissions based on April 1996 source test of Unit 4.
5. Maximum annual NH_3 emissions based on maximum hourly emission rate and 8760 hours per year of boiler operation.

Table 5.16-3 Noncriteria Pollutant Emissions for Fire Pump Engine				
	Emissions		Emission Rates for Modeling	
Compound	Max. Hourly, lb/hr[1]	Annual, tpy[2]	One-hour Average, g/s	Annual Average, g/s
Diesel exhaust particulate	1.02E-2	1.02E-3	1.29E-3	2.94E-5

Notes: 1. Based on a 30-minute engine test at 50% load.
2. Based on 200 hours per year of operation.

Table 5.16-4 Maximum Modeled Concentrations for Noncriteria Pollutants		
	Modeled Concentration, µg/m^3	
Compound	One-hour Average	Annual Average
Acetaldehyde	n.a.[1]	7.19E-3
Acrolein	1.58E-5	4.80E-8
Ammonia	2.10E+1	1.29
Benzene	2.86E-2	1.65E-3
1,3-Butadiene	n.a.	1.19E-5
Diesel exhaust particulate[2]	n.a.	6.01E-6
Ethylbenzene	n.a.	3.72E-3
Formaldehyde	7.70E-1	3.38E-2
Hexane	n.a.	2.44E-2
Naphthalene	n.a.	1.81E-4
PAHs	n.a.	9.98E-5
Propylene	n.a.	8.56E-2
Propylene Oxide	6.78E-2	4.49E-3
Toluene	1.18E-1	7.32E-3
Xylene	4.96E-2	2.95E-3

Note: 1. n.a.: no acute REL identified
2. Concentration shown is concentration at location of maximum impacts of other pollutants.

ATTACHMENT 5.16-1

HRA MODEL INPUT AND OUTPUT FILES

Calculation of Cancer Risk
ESPR Project

Pollutant Name	Max. Modeled Annual Avg Conc, ug/m3	Unit Risk, (ug/m3)-1 in one million	Multipathway Adjustment Factor (1)	Cancer Risk in one million
Acetaldehyde	7.19E-03	2.70E+00	1	1.94E-02
Benzene	1.65E-03	2.90E+01	1	4.79E-02
1,3-Butadiene	1.19E-05	1.70E+02	1	2.03E-03
Diesel exhaust particulate (2)	6.01E-06	3.00E+02	n/a	1.80E-03
Formaldehyde	3.38E-02	6.00E+00	1	2.03E-01
PAHs (as benzo(a)pyrene)	9.98E-05	1.10E+03	5.9	6.48E-01
Propylene oxide	4.49E-03	3.70E+00	1	1.66E-02
Total				9.38E-01

Note 1. Multipathway adjustment factor calculated from ARB HRA model output; includes mothers' milk.

2. Concentration for Diesel exhaust particulate is concentration at location of maximum impact for other compounds.

Calculation of Chronic Inhalation Hazard Index
ESPR Project

Pollutant Name	Max. Modeled Annual Avg Conc, ug/m3	Chronic REL, ug/m3 (1)	Toxicological Endpoints	Chronic Inhalation Hazard Index
Acrolein	4.80E-08	2.00E-02	Respiratory irritation	2.40E-06
Ammonia	1.29E+00	2.00E+02	Respiratory irritation	6.46E-03
Acetaldehyde	7.19E-03	9.00E+00	Respiratory system	7.99E-04
Benzene	1.65E-03	6.00E+01	Hematopoietic system; development; nervous system	2.75E-05
Diesel exhaust	6.01E-06	5.00E+00	Respiratory system	1.20E-06
Ethylbenzene	3.72E-03	2.00E+03	Development; alimentary system (liver); kidney; endocrine system	1.86E-06
Formaldehyde	3.38E-02	3.00E+00	Respiratory system; eyes	1.13E-02
Hexane	2.44E-02	7.00E+03	Nervous system	3.49E-06
Naphthalene	1.81E-04	9.00E+00	Respiratory system	2.02E-05
Propylene	8.56E-02	3.00E+03	Respiratory system	2.85E-05
Propylene oxide	4.49E-03	3.00E+01	Respiratory system	1.50E-04
Toluene	7.32E-03	3.00E+02	Nervous system; respiratory system; development	2.44E-05
Xylene	2.95E-03	7.00E+02	Nervous system; respiratory system	4.21E-06
Total				1.88E-02

California Air Resources Board

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Office of Environmental Health Hazard Assessment

Health Risk Assessment Program

Version 2.0e

ACUTE INHALATION EXPOSURE REPORT

Run Made By

nlm

sr

Project : NRG El Segundo

Nov. 13, 2000

Pollutant Database Date : Oct. 5, 2000
Database Reference..... : CAPCOA Risk Assessment Guidelines

DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

MAX. 1-HR EMISSION RATE INFORMATION

File: ONEHOUR.M96

Pollutant Name	Emission Rate (g/s)
ACROLEIN	1.576E-05
AMMONIA	2.098E+01
BENZENE	2.860E-02
FORMALDEHYDE	7.700E-01
PROPYLENE OXIDE	6.780E-02
TOLUENE	1.178E-01
XYLENES	4.955E-02

ACUTE INHALATION HAZARD INDEX

Pollutant	Resp	CV/BL	CNS	Eye	Repro	Kidn	GI/LV	Immun
ACROLEIN	<.0001	--	--	<.0001	--	--	--	--
AMMONIA	0.0066	--	--	0.0066	--	--	--	--
BENZENE	--	<.0001	--	--	<.0001	--	--	<.0001
FORMALDEHYDE	0.0082	--	--	0.0082	--	--	--	0.0082
PROPYLENE OXIDE	<.0001	--	--	<.0001	<.0001	--	--	--
TOLUENE	<.0001	--	<.0001	<.0001	<.0001	--	--	--
XYLENES	<.0001	--	--	<.0001	--	--	--	--
Total Acute	0.0149	<.0001	<.0001	0.0149	<.0001	--	--	0.0082

A Zero Background Concentration file was used
to perform this analysis, therefore, there is
no contribution from background pollutants.

California Air Resources Board

And

Office of Environmental Health Hazard Assessment

Health Risk Assessment Program

Version 2.0e

CHRONIC NONINHALATION EXPOSURE REPORT

Run Made By

nlm

sr

Project : NRG El Segundo

Nov. 13, 2000

Pollutant Database Date : Oct. 5, 2000
Database Reference..... : CAPCOA Risk Assessment Guidelines

DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

ANNUAL AVERAGE EMISSION RATE INFORMATION

File: ANNAVG.E96

Pollutant Name	Emission Rate (g/s)
1,3-BUTADIENE	1.193E-05
ACETALDEHYDE	7.188E-03
ACROLEIN	4.795E-08
AMMONIA	1.291E+00
BENZENE	1.651E-03
ETHYL BENZENE	3.724E-03
FORMALDEHYDE	3.382E-02
NAPHTHALENE	1.814E-04
PAH:BENZ(A)ANTHRACENE	9.981E-05
PROPYLENE (PROPENE)	8.558E-02
PROPYLENE OXIDE	4.490E-03
TOLUENE	7.321E-03
XYLENES	2.950E-03

EXPOSURE ROUTE INFORMATION

File: EXPOSURE.I96

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Deposition Velocity (m/s) .....:  0.020

Fraction of Homegrown Produce .:  0.000

Dilution Factor for Farm/Ranch X/Q (ug/m3)/(g/s) ....:   0.0000
Fraction of Animals' Diet From Grazing ..............:   0.0000
Fraction of Animals' Diet From Impacted Feed ........:   0.0000

Fraction of Animals' Water Impacted by Deposition ...:   0.0000

  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume Changes .......:  0.000E+00


Fraction of Meat in Diet Impacted ..: 0.0000

  Beef ................: 0.0000
  Pork ................: 0.0000
  Lamb/Goat ...........: 0.0000
  Chicken .............: 0.0000

Fraction of Milk in Diet Impacted ..: 0.0000

  Goat Milk Fraction ..: 0.0000

Fraction of Eggs in Diet Impacted ..: 0.0000


Fraction of Impacted Drinking Water : 0.0000

  X/Q at water source ..:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00


Fraction of Fish from Impacted Water: 0.0000

  X/Q at Fish Source ...:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00

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CHRONIC NONINHALATION EXPOSURE

Pollutant	Avg. Dose (mg/kg-d)	REL (mg/kg-d)	Avg Dose/REL
1,3-BUTADIENE	---	---	---
ACETALDEHYDE	---	---	---
ACROLEIN	---	---	---
AMMONIA	---	---	---
BENZENE	---	---	---
ETHYL BENZENE	---	---	---
FORMALDEHYDE	---	---	---
NAPHTHALENE	7.76E-08	---	---
PAH:BENZ(A)ANTHRACENE	2.24E-08	---	---
PROPYLENE (PROPENE)	---	---	---
PROPYLENE OXIDE	---	---	---
TOLUENE	---	---	---
XYLENES	---	---	---

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Health Risk Assessment Program

Version 2.0e

CHRONIC INHALATION EXPOSURE REPORT

Run Made By

nlm

sr

Project : NRG El Segundo

Nov. 13, 2000

Pollutant Database Date : Oct. 5, 2000
Database Reference..... : CAPCOA Risk Assessment Guidelines

DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

ANNUAL AVERAGE EMISSION RATE INFORMATION

File: ANNAVG.E96

Pollutant Name	Emission Rate (g/s)
1,3-BUTADIENE	1.193E-05
ACETALDEHYDE	7.188E-03
ACROLEIN	4.795E-08
AMMONIA	1.291E+00
BENZENE	1.651E-03
ETHYL BENZENE	3.724E-03
FORMALDEHYDE	3.382E-02
NAPHTHALENE	1.814E-04
PAH:BENZ(A)ANTHRACENE	9.981E-05
PROPYLENE (PROPENE)	8.558E-02
PROPYLENE OXIDE	4.490E-03
TOLUENE	7.321E-03
XYLENES	2.950E-03

CHRONIC INHALATION HAZARD INDEX

Pollutant	Resp	CV/BL	CNS	Skin	Repro	Kidn	GI/LV	Immun
ACETALDEHYDE	0.0008	--	--	--	--	--	--	--
ACROLEIN	<.0001	--	--	<.0001	--	--	--	--
AMMONIA	0.0065	--	--	--	--	--	--	--
BENZENE	--	<.0001	<.0001	--	<.0001	--	--	--
ETHYL BENZENE	--	--	--	--	<.0001	<.0001	<.0001	--
FORMALDEHYDE	0.0113	--	--	0.0113	--	--	--	--
NAPHTHALENE	<.0001	--	--	--	--	--	--	--
PROPYLENE (PROP	<.0001	--	--	--	--	--	--	--
PROPYLENE OXIDE	0.0001	--	--	--	--	--	--	--
TOLUENE	<.0001	--	<.0001	--	<.0001	--	--	--
XYLENES	<.0001	--	<.0001	--	--	--	--	--
Total Chronic	0.0188	<.0001	<.0001	0.0113	<.0001	<.0001	<.0001	--

A Zero Background Concentration file was used to perform this analysis, therefore, there is no contribution from background pollutants.

California Air Resources Board

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Office of Environmental Health Hazard Assessment

Health Risk Assessment Program

Version 2.0e

INDIVIDUAL CANCER RISK REPORT

Run Made By

Project :

Nov. 13, 2000

Pollutant Database Date : Oct. 5, 2000
Database Reference..... : CAPCOA Risk Assessment Guidelines

DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

ANNUAL AVERAGE EMISSION RATE INFORMATION

File: ANNAVG.E96

Pollutant Name	Emission Rate (g/s)
1,3-BUTADIENE	1.193E-05
ACETALDEHYDE	7.188E-03
ACROLEIN	4.795E-08
AMMONIA	1.291E+00
BENZENE	1.651E-03
ETHYL BENZENE	3.724E-03
FORMALDEHYDE	3.382E-02
NAPHTHALENE	1.814E-04
PAH:BENZO(A)PYRENE	9.980E-05
PROPYLENE (PROPENE)	8.558E-02
PROPYLENE OXIDE	4.490E-03
TOLUENE	7.321E-03
XYLENES	2.950E-03

EXPOSURE ROUTE INFORMATION

File: EXPOSURE.I96

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Deposition Velocity (m/s) .....:  0.020

Fraction of Homegrown Produce .:  0.000

Dilution Factor for Farm/Ranch X/Q (ug/m3)/(g/s) ....:   0.0000
Fraction of Animals' Diet From Grazing ..............:   0.0000
Fraction of Animals' Diet From Impacted Feed ........:   0.0000

Fraction of Animals' Water Impacted by Deposition ...:   0.0000

  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume Changes .......:  0.000E+00


Fraction of Meat in Diet Impacted ..: 0.0000

  Beef ................: 0.0000
  Pork ................: 0.0000
  Lamb/Goat ...........: 0.0000
  Chicken .............: 0.0000

Fraction of Milk in Diet Impacted ..: 0.0000

  Goat Milk Fraction ..: 0.0000

Fraction of Eggs in Diet Impacted ..: 0.0000


Fraction of Impacted Drinking Water : 0.0000

  X/Q at water source ..:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00


Fraction of Fish from Impacted Water: 0.0000

  X/Q at Fish Source ...:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00

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44 YEAR
INDIVIDUAL CANCER RISK BY POLLUTANT AND ROUTE

Pollutant	Air	Soil	Skin	Garden	MMilk	Other
1,3-BUTADIENE	1.27E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
ACETALDEHYDE	1.22E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
BENZENE	3.01E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FORMALDEHYDE	1.28E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
PAH:BENZO(A)PYR	6.90E-08	1.06E-07	6.74E-08	0.00E+00	2.72E-07	0.00E+00
PROPYLENE OXIDE	1.04E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Route Total	2.51E-07	1.06E-07	6.74E-08	0.00E+00	2.72E-07	0.00E+00

TOTAL RISK: 6.96E-07

70 YEAR
INDIVIDUAL CANCER RISK BY POLLUTANT AND ROUTE

Pollutant	Air	Soil	Skin	Garden	MMilk	Other
1,3-BUTADIENE	2.03E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
ACETALDEHYDE	1.94E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
BENZENE	4.79E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FORMALDEHYDE	2.03E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
PAH:BENZO(A)PYR	1.10E-07	1.64E-07	1.04E-07	0.00E+00	0.00E+00	0.00E+00
PROPYLENE OXIDE	1.66E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Route Total	3.99E-07	1.64E-07	1.04E-07	0.00E+00	0.00E+00	0.00E+00

TOTAL RISK: 6.67E-07